BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	**Chair**
Hwikwon Ham	**Commissioner**
Audrey C. Partridge	**Commissioner**
Joseph K. Sullivan	**Commissioner**
John A. Tuma	**Commissioner**

In the Matter of the Application for a Certificate of Need for the Gopher to Badger Link 765kVHigh Voltage Transmission Line Project	DOCKET NO. ET3, E002/CN-25-121
In the Matter of the Application for a Certificate of Need for the "Power on Midwest" 765kVHigh Voltage Transmission Line Project	DOCKET NO. ET3, E002/CN-25-117 (CN-25-118, CN-25-119, CN-25-120)

NORTH ROUTE GROUP AND NO765MN

REQUEST FOR A CONTESTED CASE AND JOINT HEARING
DOCKETS CN-25-117 AND CN-25-121

The North Route Group and NO765MN (hereinafter "NRG and NO765MN[1]") request that Dockets CN-25-117 and CN-25-121 be consolidated,[2] that a joint hearing be held, and hereby request that the ultimate docket be referred to the Court of Administrative Hearings for a contested case. Minn. Stat. §216B.243, Subd. 4; Minn. R. 7829.1000; Minn. R. 7849.1900. If/when the Commission declares these applications complete, many material issues and questions remain. We need answers sufficient to inform the record, sufficient to provide a basis

[1] For the record, it is "NRG and NO765MN" and not "Legalectric group." Unlike the "Joint Commenters," these are distinct groups with distant locations, directly affected by differing transmission proposals in different segments, with some distinct non-conflicting issues, and some shared issues. "NRG and NO765MN" is the conjoined name of the party.
[2] See NRG and NO765MN Supplemental Comment and Request for Consolidated Case.

for a Commission decision about need. This is the job of the Public Utilities Commission.

Commerce-DER said it clearly:

> Even though the project was first proposed at the regional level, reviewing the Applicant's petition through the CN process gives the Commission the opportunity to weigh in on behalf of the Minnesota's ratepayers. **It is essential that the Commission and other state agencies have the authority to advocate for Minnesota's ratepayers.**

DER Commerce, Comments, p. 1 (emphasis added).

The Public Utilities Commission is the regulator, the decider, for the State of Minnesota, and the Commission must not abdicate its authority. The Commission is responsible to the ratepayers and the people of Minnesota, including the landowners who would have to sacrifice their property for these transmission lines to be built. MISO is not the regulator and MISO "approval" means that the marketing organization of utilities and associated electric and energy corporate members think it's an economically good idea to expand transmission, and these same members receive the benefits touted by MISO in Tranche 2.1. The "approval" of MISO is not a free pass – the burden of proof is on the Applicants to demonstrate that the projects are needed, as defined by Minnesota law. Minn. Stat. §216B.243, Subd. 3. This can best be demonstrated through a contested case. Minn. Stat. §216B.243, Subd. 4; Minn. R. 7829.1000; Minn. R. 7849.1900.

I. **<u>SUFFICIENT CONTESTED ISSUES OF FACT HAVE BEEN RAISED BY NRG AND NO765MN AND/OR COMMERCE-DER IN "GOPHER TO BADGER" AND "POWER ON MIDWEST" TO TRIGGER REERRAL FOR A CONSOLIDATED AND JOINTCONTESTED CASE.</u>**

Both NRG and NO765MN have raised many issues of fact that are contested, and there are many subjects that require additional facts before a need decision can be justified. Commerce-DER appropriately notes the distinction between "completeness" of Applicant's submission of information required by rule and the Commission's Certificate of Need review:

> The Department finds that the Applicants' petition is substantially complete. This finding only addresses completeness, an administrative determination of the information provided.

DER Initial Comments, p. 3.

NRG and NO765MN raised contested and substantive issues in its Initial Comment in the Gopher to Badger docket, and although NRG and NO765MN did not provide comments on the Power on Midwest docket, most of the issues below apply as well to the Power on Midwest docket:

- Outdated economic modeling assumptions aren't sufficient to demonstrate need
- MISO's cost/benefit analysis must use current numbers to determine whether a project is feasible, much less conveys a benefit
- The Gopher to Badger transmission line does not provide benefits for the proposed transmission corridor
- MISO's Independent Market Monitor has raised questions about cost, alternatives, and challenges the MISO claimed need for Tranche 2.1. Minnesota's Commission should as well
- Many transmission lines have been proposed and permitted in the area with similar or identical beginning and endpoints that call the "need" for this project into question.
- Reasonable and available system alternatives, individually or in combination, may obviate the "need" for this project.
- The Applicants' claim that "consumers" will be responsible for only a small portion of the cost of this project is contested
- Costs of individual projects are in 2024 dollars, with extreme cost increases expected
- The upper bound of capacity of this line, amps, MW and MVA, is a contested issue of fact
- Line losses for this individual project is an issue of fact
- The Applicants' claim that the cost of Direct Current transmission generally and the cost of necessary converters is prohibitive -- that is an issue of fact
- Applicants claim the cost of undergrounding DC is cost prohibitive
- What are the project's "three delivery points" in Minnesota and three additional delivery points outside of Minnesota
- Applicants argue excess energy and the need to export that excess energy demonstrates a need for this project
- When need claim is based on desire for export capability, and the substations are set out on the map above
- Where 345kV support lines are "steady-state stability" problems, what is the support system if the 765kV system goes down?

NRG an NO765MN Initial Comment, pps. 10-27.

The Department of Commerce-DER, while stating that the application is substantially complete, also raises many questions that must be answered. "In reviewing the petition for completeness, the Department found items that may be lacking in context, explanation, or alternate information." Commerce DER Initial Comment, p. 3, Gopher to Badger, CN-25-121. Some of these points are minor and were corrected in Reply Comments, but many of these issues are sufficient to trigger a contested case, particularly those about costs, impact of tariffs, and MISO Variance Analysis, material issues of fact also raised by NRG and NP765MN:

- Completeness checklist does not match up with content.
- The Department would appreciate a review of costs and benefits to ratepayers from enabling more transmission capacity from advanced conductor technologies, beyond ACSR. This could include how various additional transmission components, such as line sag, temperature, and weather conditions, affect transmission line output.
- The Department recommends supplying additional information on how the Applicants decided to use these ACSR conductors, and whether any advanced conductors were included in that study, in Applicant's reply comments.
- The Department recommends that Applicants discuss how they decided on conductor arrays, type and size. The Department also recommends discussing other types and technologies for conductors, such as advanced conductors.
- The Department recommends Applicants clarify that "doublecircuit" modifies the 161 kV, not the 765 kV portion of the line in future filings.
- The Department recommends that Applicants add more details of how the project components cost estimates were calculated and what portion is related to risk reserves.
- The Department likewise recommends Applicants provide more details on project cost assumptions and how they are affected with section 232 tariffs for steel, copper and aluminum, in addition to any other potential cost drivers.
- What changes, if any, do Applicants envision to cost estimates, following the Supreme Court's decision declaring the International Emergency Economic Powers Act (IEEPA) tariffs unconstitutional?
- The Department recommends providing additional information as to how the proposed project's cost estimates with risk reserves relate to the LRTP and Multi-Value Project (MVP) variance analysis process.
- Based on these costs for O&M expenses, the Department recommends that Applicants provide more details of the assumptions underpinning these O&M cost estimates. For
- example, do the cost estimates feature an escalator to account for inflation? It is likely that costs near the end of the useful lifespan of the proposed project will require more

maintenance than in early years. The Department recommends Applicants provide their cost escalator, if used.

- The petition should provide additional details about how involved they were in planning assumptions in MTEP and Futures planning. For example, what data did Applicants provide to MISO beyond integrated resource plan data and state policy language, if any? How much did MISO consult Dairyland and Xcel as transmission owners (TOs), versus consulting with TOs across the MISO North region?
- Appendix D of the Applicant's petition features a list of Xcel's revenue requirements. On pg. 2, Xcel lists its all-in project revenue requirement as $1.518 billion, with a net cost to MN jurisdiction as $1.112 billion. However, on page 9 of Appendix D, the Applicants then list that the all-in project revenue requirement is $1.971 billion, with a net cost to the MN jurisdiction as $1.444 billion. The Department recommends the Applicants provide their derivations of these numbers.
- The Department recommends that Applicants provide more details and calculations for coming to these numbers in Appendix D, including how the different dollar amounts for 'Total Project Costs' relate to each other. Applicants should also explain how these numbers relate to the overall costs of the project as reported in Section 2.5 of the initial petition?
- The Department recommends that the Applicants discuss whether southeastern Minnesota currently has the workforce capable of providing 800 personnel with sufficient experience and training to construct this project. If the workforce is not sufficient, Applicants should discuss any workforce development programs that may be needed.
- The Department recommends the Applicant provide more insight into which, if any, of the binding constraints in Figure 6.4-2 also appear in the GETs Report. This includes information about how the proposed project will implement FERC Order 881, requiring all transmission owners to implement ambient-adjusted ratings (AAR) on their transmission lines. Additionally, FERC Order 1920 requires transmission owners to consider implementation of advanced transmission technologies (ATTs), such as grid enhancing hardware and software, such as dynamic line rating, advanced power flow control, advanced conductor materials and other innovations. The Department recommends the Applicant provide more detail as to how the Applicants could comply with the aforementioned FERC Orders, which mandate consideration of ATTs, in its petition.
- The Department recommends Applicants provide additional information for how Applicants plan to implement AAR and other advanced transmission technologies (ATTs) as part of the proposed project as required by FERC Order 881 and FERC Order 1920, respectively.

Commerce-DER Initial Comment for Power on Minnesota, pps. 4-10. DER also offers specific Comments on Completeness on pages 11-18.

Similar comments were made in Commerce-DER Initial Comment:

- Can the Applicants ensure that the completeness checklist matches the location of the information or data in the petition?

- The Applicants claim they have “squeezed every drop” of capacity out of existing lines, and new lines are proposed only after all other options have been exhausted. If this were the case, the Applicants would have upgraded all their existing lines with grid enhancing technologies (GETs) or advanced reconductoring.
- The Applicants point to congestion as one of the primary needs of the project. The Department understands that GETs could not achieve the same congestion mitigation benefits as the proposed project, but that does not mean that GETs should not be utilized on existing lines. If congestion is currently one of the main challenges facing the electric grid and could be mitigated with greater line capacity why did Xcel Energy, GRE, and other MTO only identify 12 solutions in the 2025 GETs Report?
- Can the Applicants explain how GETs and other upgrades such as, but not limited to, advanced reconductoring, could increase capacity, and the potential costs compared to a rebuild or new line construction, like the proposed project?
- The Applicants stating that the 2025 GETs Report addresses 30 additional solutions is misleading. The 2025 GETs Report only identified 12 constraints where a new solution is identified and the proposal meets the payback period. The other 18 solutions were pulled from the Grid North Partners study from 2023.
- Could GETs be used to upgrade the proposed project after the inservice date?
- How could GETs be used during the construction of the proposed project to mitigate congestion and curtailment caused by forced outages?
- How many MWs of low-cost power could the project free up?
- The only societally beneficial use of the project that the Applicants specifically refer to is carbon reduction benefits. Can the Applicants point to any other societal benefits of the project? The proposed project claims to reduce congestion. This would theoretically help to reduce rates and allow the lowest price renewable resources to reach the load, is that not a societal benefit? The project could also reduce the curtailment of wind energy from
- southeast Minnesota, an issue that the state has been facing for years. Can the Applicants provide an economic analysis of how the project prevents curtailment and increases revenue to counties in the form of wind production tax credits?
- A large portion of the proposed route will be in southeast Minnesota. Will the communities there benefit from infrastructure they are housing?
- The Applicants say the project will use ACSR Bunting conductor, or a similar performing conductor. Why wouldn’t the project be able to use the Bunting Conductor and can you give examples of a similar conductor? Would there be a substantial price difference for an alternative conductor?
- Can the Applicants explain how GETs could increase reliability, mitigate curtailment and reduce congestion as an alternative to the proposed project? Additionally, how could battery energy storage systems, combined with GETs, serve as a reasonable combination of alternatives to the proposed project?
- Do the Applicants include operations and maintenance costs in the total project costs? As per their exemption, Xcel Energy provided an annual revenue requirement, and notes that the revenue requirement calculations do not account for future O&M costs. How does Xcel Energy, and the Applicants generally, plan on accounting for operations and maintenance costs?
- Appendix D, Xcel Energy’s annual revenue requirement, has no cover letter or explanation. The Appendix includes several tables with no captions or information. The

only explanation of the Appendix is one paragraph in the petition. Can the Applicants respond to these comments with an updated Appendix D?

- What is the Applicants plan if the South Dakota or Iowa sections of the project are completed before or after the Minnesota segments? If the Minnesota segment is completed first, is it energized, or will all segments have to be built for the project to be energized? Are the Applicants communicating with other states' utilities to coordinate this?

Commerce-DER Initial Comment, Power on Midwest, pps. 4-8. DER also offers specific Comments on Completeness, pages 8-18.

An example of additional information needed can be found in the Variance Analysis Information Letter for PUC Docket Cn-22-416, for the Northland Reliability Project, where project costs were found to have risen by **43%**! MISO is asking or cost specific information for "each individual facility," in that project, below is request for cost information on a project's line replacement:

5) **Facility 27054 (GRE)**

a) Please update the table below, which is derived from MTEP21 Appendix A, with any proposed changes. When updating, please craft "Description" verbiage at approximately the same summary-level shown in the "Original" column of the table. There will be an opportunity to provide additional details below the table.

Facility ID	27054 – *Original*	27054 – *Updated*
Facility Type	LNup	
From Sub	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W	
To Sub	Benton County	
Max kV	345	
Min kV		
Emerg. Rating	3000 A	
Expected ISD	6/1/2028	
Description	Replace the existing Benton County-Sherco line to accommodate a rating greater than 3000 Amps. Including north deadend structure for new conductor. This line will tie to Cassie Crossing.	
Miles Upgrade	14.1	
Miles New		
Estimated Cost 2022$	$47,400,000	
Estimated Cost Nominal$	Not calculated in MTEP	

b) **Scope:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the scope of work for this facility (as summarized above in the "Description," "Miles Upgrade," "Miles New," or "Emerg. Rating" fields). For substation facilities, describe any scope changes along with the rationale; for existing substation modifications, include substation one-line drawings that depict the substation before the project and after the project with the proposed project modifications called out; for new substations, include substation one-line drawings that highlight the scope changes. For transmission line facilities, describe any scope changes along with the rationale; include a simplified transmission diagram that illustrates the scope changes.

c) **Schedule:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive delays in the schedule for energization of this facility (as shown above in "Expected ISD" field) that would cause a delay in the expected ISD for the entire LRTP Project.

d) **Cost:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the estimated cost for this facility (as shown above in the "Estimated Cost 2022$" field). Please update both the 2022$ and Nominal$ fields if documenting a change to the estimated cost.

e) Please provide additional details (cause, rationale, circumstances, etc.) about any other fields that you have updated in the table above.

f) Please provide any other information about this facility that you would like MISO to consider for Variance Analysis.

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Attachment B, MISO Variance Analysis Information Letter, p. 11 of 15, March 6, 2026.

Commerce-DER raises the matter of MISO Variance Analysis, and because of the extreme economic impacts we're seeing with constantly changing tarriffs, revocation of energy policies and institutions of others that affect transmission projects, uncertainty that makes long-range planning… uncertain, based on the uncharted activities of the current administration in 2025 and now 2026, this cost inquiry and analysis must be considered for each and every transmission line in the Commission process, every energy project as well, projects whether permitted and not yet constructed, in the process, or under review.

II. A CONTESTED CASE IS NECESSARY FOR THIS FIRST OF A KIND 765kV TRANSMISSION PROJECT FOR BOTH MINNESOTA AND THE APPLICANTS, COSTING OVER $6 BILLLION AND STRETCHING FROM THE WESTERN BORDER TO THE MISSISSIPPI AND BEYOND.

The North Route Group and NO765MN request that Dockets CN-25-117 and CN-25-121 be consolidated,[3] that a joint hearing be held, and hereby request that the ultimate docket be referred to the Court of Administrative Hearings for a contested case. Minn. Stat. §216B.243, Subd. 4; Minn. R. 7829.1000; Minn. R. 7849.1900. Even if the applications are deemed complete, that only covers the Application itself, that the requisite materials are included in the application. The Applicant has the burden of proof and many material issues and questions remain.

For a project to be granted a Certificate of Need, the applicants must demonstrate that the projects are needed, as defined by Minnesota law. Minn. Stat. §216B.243, Subd. 3. This can best be demonstrated through a contested case. Minn. Stat. §216B.243, Subd. 4; Minn. R. 7829.1000; Minn. R. 7849.1900.

At this time, NRG and NO765KV ask that the Commission act on the multiple Requests Filed, in order of appearance.

[3] See NRG and NO765MN Supplemental Comment and Request for Consolidated Case.

First, we request that the Gopher to Badger (CN-25-121) and Power on Midwest (CN-25-117, 118, 119, and 120) be consolidated and reviewed jointly, as requested in the Supplemental Comments, Petition for Consolidation, and Request for Stay, filed separately.

Second, we request that the Commission grant Applicants' request for a stay for the Gopher to Badger transmission project, CN-25-121, to which NRG and NO765MN agree, and we request that the Commission also stay the consolidated Power on Midwest, CN-25-117 docket, until that route application is filed. See Supplemental Comments, Petition for Consolidation and Request for Stay, filed separately.

Third, during the stay, we request, to avoid delay and gain information necessary to inform the record, that participating parties may begin Discovery as provided under a typical First Scheduling Order. See attached example.

Fourth, that the Commission grant a contested case and refer the Gopher to Badger (CN-25-121) and Power on Midwest (CN-25-117, 118, 119, and 120) to the Court of Administrative Hearings, and that the Commission Order that the stay continue until the Route applications are filed.

Respectfully submitted:

Carol A Overland

Dated: March 9, 2026

Carol A. Overland MN Lic. 254617
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Northland Reliability Project

March 6, 2026

VIA E-FILING

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

Re: Variance Analysis Information (Order Point 4 and Route Permit Section 6.10)
In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line
MPUC Docket Nos. E015,ET2/TL-22-416 and E015,ET2/TL-22-415

Dear Ms. Bergman:

On February 28, 2025, the Minnesota Public Utilities Commission ("Commission") issued an order ("Order") granting Great River Energy and Minnesota Power ("Permittees") a Certificate of Need and issuing a Route Permit for the Northland Reliability Project ("Project"). On December 16, 2025, the Permittees notified the Commission that the Midcontinent Independent System Operator, Inc. ("MISO") initiated a Variance Analysis under Attachment FF of the MISO Tariff for the Project.

In compliance with Order Point 4 and Section 6.10 of the Route Permit, the Permittees herby submit the information provided by the Permittees to MISO as part of the MISO Variance Analysis process, consistent with the Permittees' MISO Tariff.[1] A copy of MISO's request for information is included as **Attachment A**, and a copy of the Permittees' responses is included as **Attachment B**.

If you have any questions or need additional information, please contact Christian Winter at CWinter@mnpower.com or Matthew Ellis at MEllis@GREnergy.com.

/s/ Christian Winter
Christian Winter
Minnesota Power
Manager – Regional Transmission Planning

/s/ Matthew Ellis
Matthew Ellis
Great River Energy
Director – Transmission Planning & Compliance

cc: Service Lists

[1] The Permittees' submitted the information to MISO on February 27, 2026.

February 4, 2026

Matt Ellis
Director, Transmission Planning & Compliance
Great River Energy (GRE)
12300 Elm Creek Blvd N,
Maple Grove, MN 55369

Christian Winter
Manager, Regional Transmission Planning
Minnesota Power (MP)
30 W Superior Street
Duluth, MN 55802

RE: Request for Information #1 for Variance Analysis on MTEP21 LRTP Project 03 Iron Range – Benton County – Big Oaks

Dear Mr. Ellis and Mr. Winter:

Pursuant to the December 15, 2025 correspondence, Midcontinent Independent System Operator, Inc. ("MISO") determined that reasonable grounds for Variance Analysis exist in relation to the Iron Range – Benton County – Big Oaks Long Range Transmission Planning ("LRTP") Tranche 1 project (hereinafter referred to as the "Project"), designated to both GRE and MP, on the grounds that the cost increases reported by both GRE and MP exceed the Tariff-provided 25% variance threshold allowed in relation to the original MTEP21 project Baseline Cost Estimate (BCE) (in 2022$) listed in Appendix A for the Project. Accordingly, MISO formally commenced Variance Analysis for the Project on December 15, 2025. This letter to GRE and MP, which is the first formal Request for Information ("RFI #1"), represents phase 2, milestone 5 of the Variance Analysis process[1] as diagrammed and described in the "Variance Analysis Process Overview" section of this letter.

Variance Analysis Process Overview

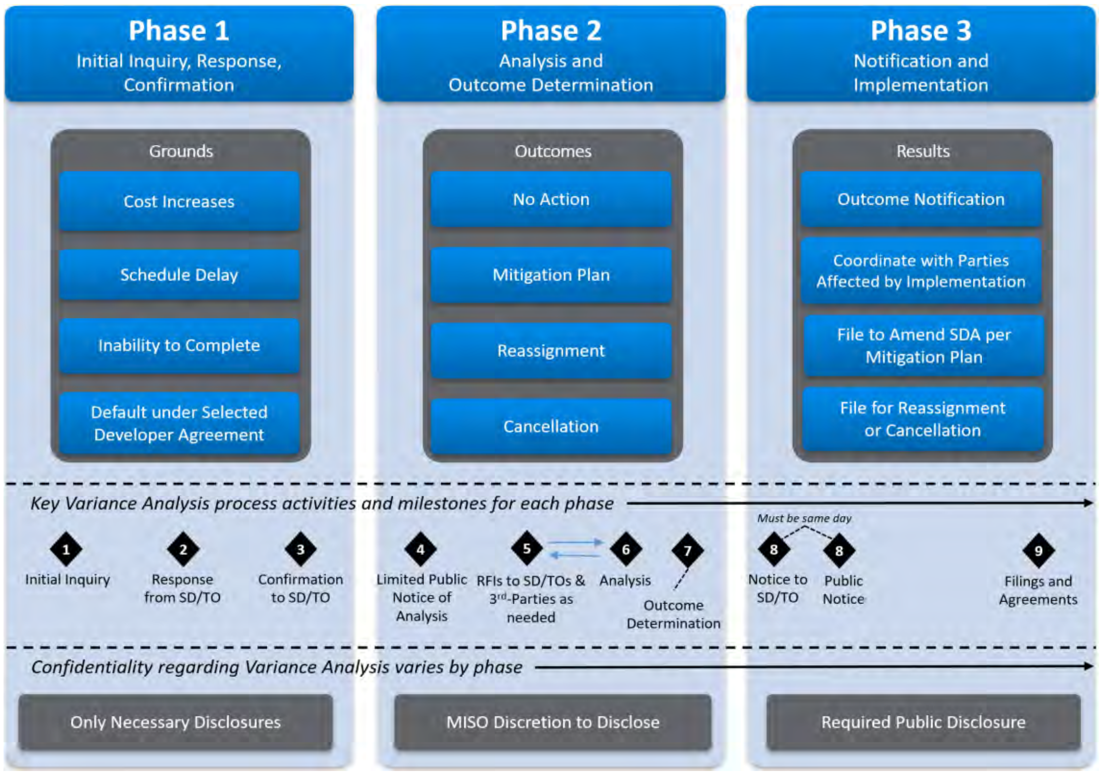
Variance Analysis, which is set forth within Attachment FF, Section IX of the MISO Tariff, is MISO's process for addressing challenges that arise during project development. As defined in the Tariff and illustrated in the graphic on page 2, the process consists of three phases.

In view of previous correspondence among MISO, GRE and MP staff, milestone 1 (initial inquiry from MISO), milestone 2 (response from GRE and MP), milestone 3 (confirmation of commencement of Variance Analysis by MISO), and milestone 4 (limited public notice of analysis by MISO) of the Variance Analysis process have been completed.

At this time, MISO believes it is appropriate to proceed to milestone 5 of the Variance Analysis process (i.e., this RFI #1), which is the purpose of this letter. Collectively, milestones 5 (RFIs to SD/TOs) and 6 (analysis) represent MISO's process of requesting and analyzing information from GRE and MP. At its

[1] Pursuant to Attachment FF, Section IX.D.1 of the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff").

discretion, MISO may issue additional RFIs to collect new information or clarify provided information prior to proceeding to milestone 7 (outcome determination by MISO).



Guidelines describing confidentiality during the Variance Analysis process are contained in Attachment FF, Section IX.F of MISO's Tariff. During phase 1, MISO must keep its discussions with affected parties confidential unless additional disclosures are necessary. During phase 2, MISO shall publicly state that Variance Analysis has commenced on the Project in the interest of transparency related to the process and may provide a high-level explanation of why Variance Analysis was commenced. During phase 2, MISO also has the option to disclose limited information to third-parties, as needed, to support its analysis. At the beginning of phase 3, MISO is required to notify GRE and MP of the outcome determination, as well as publicly post information about the determination on its website.

Next Steps and Requested Acknowledgement from GRE and MP

At your earliest opportunity, please confirm receipt of this RFI #1 for Variance Analysis for the Project via email to jdoner@misoenergy.org.

MISO requests that GRE and MP provide responses to this RFI #1 no later than **February 27, 2026**. Please contact me if you have any questions.

Respectfully submitted,

Midcontinent Independent System Operator, Inc.

By __*/s/ Jeremiah Doner*____
Jeremiah Doner
Director of Cost Allocation and Competitive Transmission

Variance Analysis RFI #1 Questions for GRE and MP

1) General Topics

a) If GRE and MP have summary materials that have been prepared to explain the respective variances that triggered Variance Analysis on the facilities that comprise LRTP Project 3, please provide them. (GRE and MP are not required to create summary materials, beyond those already provided, if they do not exist at this time.)

b) In this RFI #1, MISO will ask for the estimated cost of each individual facility in both 2022$ and in Nominal$.[2] In the October 10, 2025, response to MISO's initial inquiry, GRE/MP explained how it converted the estimated costs to 2022$ as follows:

"*Updated estimated costs are provided in 2022 dollars. Project cost estimates terms other than real $-2022 have been de-escalated to 2022 using 4% assumed inflation rate for labor and external contractor costs, as well as a 5.6% assumed inflation rate for materials. The amount of de-escalation per estimate line item is dependent on the project schedule's delivery or end date for that item.*"

Please confirm whether this explanation is still applicable, as well as add any clarifying statements that you wish for MISO to consider in relation to GRE/MP's internal escalation/de-escalation methodology.

[2] "Nominal$" refers to the actual dollars spent in each year of the project, without any adjustment for inflation. For example, if the project forecast is for a spend of $1M in year 1, and a spend of $1M in year 5 you would report those exact amounts for each of those years or sum the total spend as $2M, despite the fact that the purchasing power of $1M in year 5 is lower than in year 1.

2) **Facility 27051 (GRE)**

a) Please update the table below, which is derived from MTEP21 Appendix A, with any proposed changes. When updating, please craft "Description" verbiage at approximately the same summary-level shown in the "Original" column of the table. There will be an opportunity to provide additional details below the table.

Facility ID	27051 – *Original*	27051 – *Updated*
Facility Type	LN	
From Sub	Cassie's Crossing (aka, Big Oaks)	
To Sub	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W	
Max kV	345	
Min kV		
Emerg. Rating	3000 A	
Expected ISD	6/1/2030	
Description	Replace existing GRE single circuit 230kV transmission line with double circuit 345kV transmission line. Both lines will tie to Benton County.	
Miles Upgrade		
Miles New	12.5	
Estimated Cost 2022$	$48,800,000	
Estimated Cost Nominal$	Not calculated in MTEP	

b) **Scope:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the scope of work for this facility (as summarized above in the "Description," "Miles Upgrade," "Miles New," or "Emerg. Rating" fields). For substation facilities, describe any scope changes along with the rationale; for existing substation modifications, include substation one-line drawings that depict the substation before the project and after the project with the proposed project modifications called out; for new substations, include substation one-line drawings that highlight the scope changes. For transmission line facilities, describe any scope changes along with the rationale; include a simplified transmission diagram that illustrates the scope changes.

c) **Schedule:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive delays in the schedule for energization of this facility (as shown above in "Expected ISD" field) that would cause a delay in the expected ISD for the entire LRTP Project.

d) **Cost:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the estimated cost for this facility (as shown above in the "Estimated Cost 2022$" field). Please update both the 2022$ and Nominal$ fields if documenting a change to the estimated cost.

e) Please provide additional details (cause, rationale, circumstances, etc.) about any other fields that you have updated in the table above.

f) Please provide any other information about this facility that you would like MISO to consider for Variance Analysis.

3) **Facility 27052 (GRE)**

a) Please update the table below, which is derived from MTEP21 Appendix A, with any proposed changes. When updating, please craft "Description" verbiage at approximately the same summary-level shown in the "Original" column of the table. There will be an opportunity to provide additional details below the table.

Facility ID	27052 – *Original*	27052 – *Updated*
Facility Type	LNup	
From Sub	Sherco	
To Sub	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W	
Max kV	345	
Min kV		
Emerg. Rating	3000 A	
Expected ISD	6/1/2028	
Description	Replace the existing Benton County-Sherco line to accommodate a rating greater than 3000 Amps. Including south deadend structure for new conductor. This line will tie to Benton County.	
Miles Upgrade	7.3	
Miles New		
Estimated Cost 2022$	$25,000,000	
Estimated Cost Nominal$	Not calculated in MTEP	

b) **Scope:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the scope of work for this facility (as summarized above in the "Description," "Miles Upgrade," "Miles New," or "Emerg. Rating" fields). For substation facilities, describe any scope changes along with the rationale; for existing substation modifications, include substation one-line drawings that depict the substation before the project and after the project with the proposed project modifications called out; for new substations, include substation one-line drawings that highlight the scope changes. For transmission line facilities, describe any scope changes along with the rationale; include a simplified transmission diagram that illustrates the scope changes.

c) **Schedule:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive delays in the schedule for energization of this facility (as shown above in "Expected ISD" field) that would cause a delay in the expected ISD for the entire LRTP Project.

d) **Cost:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the estimated cost for this facility (as shown above in the "Estimated Cost 2022$" field). Please update both the 2022$ and Nominal$ fields if documenting a change to the estimated cost.

e) Please provide additional details (cause, rationale, circumstances, etc.) about any other fields that you have updated in the table above.

f) Please provide any other information about this facility that you would like MISO to consider for Variance Analysis.

4) Facility 27053 (GRE)

a) Please update the table below, which is derived from MTEP21 Appendix A, with any proposed changes. When updating, please craft "Description" verbiage at approximately the same summary-level shown in the "Original" column of the table. There will be an opportunity to provide additional details below the table.

Facility ID	27053 – *Original*	27053 – *Updated*
Facility Type	LN	
From Sub	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W	
To Sub	Benton County	
Max kV	345	
Min kV		
Emerg. Rating	3000 A	
Expected ISD	6/1/2030	
Description	Replace existing GRE single circuit 230kV transmission line with double circuit 345kV transmission line. One line will tie to Sherco and other to Cassie Crossing.	
Miles Upgrade		
Miles New	12.5	
Estimated Cost 2022$	$48,800,000	
Estimated Cost Nominal$	Not calculated in MTEP	

b) **Scope:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the scope of work for this facility (as summarized above in the "Description," "Miles Upgrade," "Miles New," or "Emerg. Rating" fields). For substation facilities, describe any scope changes along with the rationale; for existing substation modifications, include substation one-line drawings that depict the substation before the project and after the project with the proposed project modifications called out; for new substations, include substation one-line drawings that highlight the scope changes. For transmission line facilities, describe any scope changes along with the rationale; include a simplified transmission diagram that illustrates the scope changes.

c) **Schedule:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive delays in the schedule for energization of this facility (as shown above in "Expected ISD" field) that would cause a delay in the expected ISD for the entire LRTP Project.

d) **Cost:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the estimated cost for this facility (as shown above in the "Estimated Cost 2022$" field). Please update both the 2022$ and Nominal$ fields if documenting a change to the estimated cost.

e) Please provide additional details (cause, rationale, circumstances, etc.) about any other fields that you have updated in the table above.

f) Please provide any other information about this facility that you would like MISO to consider for Variance Analysis.

5) Facility 27054 (GRE)

a) Please update the table below, which is derived from MTEP21 Appendix A, with any proposed changes. When updating, please craft "Description" verbiage at approximately the same summary-level shown in the "Original" column of the table. There will be an opportunity to provide additional details below the table.

Facility ID	27054 – *Original*	27054 – *Updated*
Facility Type	LNup	
From Sub	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W	
To Sub	Benton County	
Max kV	345	
Min kV		
Emerg. Rating	3000 A	
Expected ISD	6/1/2028	
Description	Replace the existing Benton County-Sherco line to accommodate a rating greater than 3000 Amps. Including north deadend structure for new conductor. This line will tie to Cassie Crossing.	
Miles Upgrade	14.1	
Miles New		
Estimated Cost 2022$	$47,400,000	
Estimated Cost Nominal$	Not calculated in MTEP	

b) **Scope:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the scope of work for this facility (as summarized above in the "Description," "Miles Upgrade," "Miles New," or "Emerg. Rating" fields). For substation facilities, describe any scope changes along with the rationale; for existing substation modifications, include substation one-line drawings that depict the substation before the project and after the project with the proposed project modifications called out; for new substations, include substation one-line drawings that highlight the scope changes. For transmission line facilities, describe any scope changes along with the rationale; include a simplified transmission diagram that illustrates the scope changes.

c) **Schedule:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive delays in the schedule for energization of this facility (as shown above in "Expected ISD" field) that would cause a delay in the expected ISD for the entire LRTP Project.

d) **Cost:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the estimated cost for this facility (as shown above in the "Estimated Cost 2022$" field). Please update both the 2022$ and Nominal$ fields if documenting a change to the estimated cost.

e) Please provide additional details (cause, rationale, circumstances, etc.) about any other fields that you have updated in the table above.

f) Please provide any other information about this facility that you would like MISO to consider for Variance Analysis.

6) Facility 27055 (GRE)

a) Please update the table below, which is derived from MTEP21 Appendix A, with any proposed changes. When updating, please craft "Description" verbiage at approximately the same summary-level shown in the "Original" column of the table. There will be an opportunity to provide additional details below the table.

Facility ID	27055 – *Original*	27055 – *Updated*
Facility Type	SUB	
From Sub	Benton County	
To Sub		
Max kV	345	
Min kV		
Emerg. Rating	3000 A	
Expected ISD	6/1/2030	
Description	Add 345kV 7-position breaker-and-a-half bus with 2 transformer positions and 5 line positions (one an existing modification), with two line connected 70MVAr shunt reactors on Iron Range lines, and modify 230kV position for one 230/345kV transformer	
Miles Upgrade		
Miles New		
Estimated Cost 2022$	$25,500,000	
Estimated Cost Nominal$	Not calculated in MTEP	

b) **Scope:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the scope of work for this facility (as summarized above in the "Description," "Miles Upgrade," "Miles New," or "Emerg. Rating" fields). For substation facilities, describe any scope changes along with the rationale; for existing substation modifications, include substation one-line drawings that depict the substation before the project and after the project with the proposed project modifications called out; for new substations, include substation one-line drawings that highlight the scope changes. For transmission line facilities, describe any scope changes along with the rationale; include a simplified transmission diagram that illustrates the scope changes.

c) **Schedule:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive delays in the schedule for energization of this facility (as shown above in "Expected ISD" field) that would cause a delay in the expected ISD for the entire LRTP Project.

d) **Cost:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the estimated cost for this facility (as shown above in the "Estimated Cost 2022$" field). Please update both the 2022$ and Nominal$ fields if documenting a change to the estimated cost.

e) Please provide additional details (cause, rationale, circumstances, etc.) about any other fields that you have updated in the table above.

f) Please provide any other information about this facility that you would like MISO to consider for Variance Analysis.

7) Facility 27056 (MP)

a) Please update the table below, which is derived from MTEP21 Appendix A, with any proposed changes. When updating, please craft "Description" verbiage at approximately the same summary-level shown in the "Original" column of the table. There will be an opportunity to provide additional details below the table.

Facility ID	27056 – *Original*	27056 – *Updated*
Facility Type	LN	
From Sub	Benton County	
To Sub	Riverton 230/115kV	
Max kV	345	
Min kV		
Emerg. Rating	3000 A	
Expected ISD	6/1/2030	
Description	Construct new 345kV double circuit transmission line	
Miles Upgrade		
Miles New	78	
Estimated Cost 2022$	$312,000,000	
Estimated Cost Nominal$	Not calculated in MTEP	

b) **Scope:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the scope of work for this facility (as summarized above in the "Description," "Miles Upgrade," "Miles New," or "Emerg. Rating" fields). For substation facilities, describe any scope changes along with the rationale; for existing substation modifications, include substation one-line drawings that depict the substation before the project and after the project with the proposed project modifications called out; for new substations, include substation one-line drawings that highlight the scope changes. For transmission line facilities, describe any scope changes along with the rationale; include a simplified transmission diagram that illustrates the scope changes.

c) **Schedule:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive delays in the schedule for energization of this facility (as shown above in "Expected ISD" field) that would cause a delay in the expected ISD for the entire LRTP Project.

d) **Cost:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the estimated cost for this facility (as shown above in the "Estimated Cost 2022$" field). Please update both the 2022$ and Nominal$ fields if documenting a change to the estimated cost.

e) Please provide additional details (cause, rationale, circumstances, etc.) about any other fields that you have updated in the table above.

f) Please provide any other information about this facility that you would like MISO to consider for Variance Analysis.

8) Facility 27057 (MP)

a) Please update the table below, which is derived from MTEP21 Appendix A, with any proposed changes. When updating, please craft "Description" verbiage at approximately the same summary-level shown in the "Original" column of the table. There will be an opportunity to provide additional details below the table.

Facility ID	27057 – *Original*	27057 – *Updated*
Facility Type	SC	
From Sub	Riverton 230/115kV	
To Sub		
Max kV	345	
Min kV		
Emerg. Rating	3000 A	
Expected ISD	6/1/2030	
Description	Add 4-345kV series capacitor bank groups (2 in series for each circuit) with protective bypass equipment. Impedance of series capacitor bank will be approximately 60% compensation of line	
Miles Upgrade		
Miles New		
Estimated Cost 2022$	$80,000,000	
Estimated Cost Nominal$	Not calculated in MTEP	

b) **Scope:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the <u>scope of work</u> for this facility (as summarized above in the "Description," "Miles Upgrade," "Miles New," or "Emerg. Rating" fields). For substation facilities, describe any scope changes along with the rationale; for existing substation modifications, include substation one-line drawings that depict the substation before the project and after the project with the proposed project modifications called out; for new substations, include substation one-line drawings that highlight the scope changes. For transmission line facilities, describe any scope changes along with the rationale; include a simplified transmission diagram that illustrates the scope changes.

c) **Schedule:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive delays in the <u>schedule</u> for energization of this facility (as shown above in "Expected ISD" field) that would cause a delay in the expected ISD for the entire LRTP Project.

d) **Cost:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the estimated <u>cost</u> for this facility (as shown above in the "Estimated Cost 2022$" field). Please update both the 2022$ and Nominal$ fields if documenting a change to the estimated cost.

e) Please provide additional details (cause, rationale, circumstances, etc.) about any other fields that you have updated in the table above.

f) Please provide any other information about this facility that you would like MISO to consider for Variance Analysis.

9) Facility 27058 (MP)

a) Please update the table below, which is derived from MTEP21 Appendix A, with any proposed changes. When updating, please craft "Description" verbiage at approximately the same summary-level shown in the "Original" column of the table. There will be an opportunity to provide additional details below the table.

Facility ID	27058 – *Original*	27058 – *Updated*
Facility Type	LN	
From Sub	Riverton 230/115kV	
To Sub	Iron Range 500/230kV	
Max kV	345	
Min kV		
Emerg. Rating	3000 A	
Expected ISD	6/1/2030	
Description	Construct new 345kV double circuit transmission line	
Miles Upgrade		
Miles New	78	
Estimated Cost 2022$	$312,000,000	
Estimated Cost Nominal$	Not calculated in MTEP	

b) **Scope:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the scope of work for this facility (as summarized above in the "Description," "Miles Upgrade," "Miles New," or "Emerg. Rating" fields). For substation facilities, describe any scope changes along with the rationale; for existing substation modifications, include substation one-line drawings that depict the substation before the project and after the project with the proposed project modifications called out; for new substations, include substation one-line drawings that highlight the scope changes. For transmission line facilities, describe any scope changes along with the rationale; include a simplified transmission diagram that illustrates the scope changes.

c) **Schedule:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive delays in the schedule for energization of this facility (as shown above in "Expected ISD" field) that would cause a delay in the expected ISD for the entire LRTP Project.

d) **Cost:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the estimated cost for this facility (as shown above in the "Estimated Cost 2022$" field). Please update both the 2022$ and Nominal$ fields if documenting a change to the estimated cost.

e) Please provide additional details (cause, rationale, circumstances, etc.) about any other fields that you have updated in the table above.

f) Please provide any other information about this facility that you would like MISO to consider for Variance Analysis.

10) Facility 27059 (MP)

a) Please update the table below, which is derived from MTEP21 Appendix A, with any proposed changes. When updating, please craft "Description" verbiage at approximately the same summary-level shown in the "Original" column of the table. There will be an opportunity to provide additional details below the table.

Facility ID	27059 – *Original*	27059 – *Updated*
Facility Type	SUB	
From Sub	Iron Range 500/230kV	
To Sub		
Max kV	345	
Min kV		
Emerg. Rating	3000 A	
Expected ISD	6/1/2030	
Description	Add 4-position 345kV ring bus (expandable to breaker-and-a-half bus) for 2-345/500kV transformer positions and 2 line positions (includes 2-345 kV shunt reactors on lines to Benton, est. 50 MVAR each)	
Miles Upgrade		
Miles New		
Estimated Cost 2022$	$20,000,000	
Estimated Cost Nominal$	Not calculated in MTEP	

b) **Scope:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the <u>scope of work</u> for this facility (as summarized above in the "Description," "Miles Upgrade," "Miles New," or "Emerg. Rating" fields). For substation facilities, describe any scope changes along with the rationale; for existing substation modifications, include substation one-line drawings that depict the substation before the project and after the project with the proposed project modifications called out; for new substations, include substation one-line drawings that highlight the scope changes. For transmission line facilities, describe any scope changes along with the rationale; include a simplified transmission diagram that illustrates the scope changes.

c) **Schedule:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive delays in the <u>schedule</u> for energization of this facility (as shown above in "Expected ISD" field) that would cause a delay in the expected ISD for the entire LRTP Project.

d) **Cost:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the estimated <u>cost</u> for this facility (as shown above in the "Estimated Cost 2022$" field). Please update both the 2022$ and Nominal$ fields if documenting a change to the estimated cost.

e) Please provide additional details (cause, rationale, circumstances, etc.) about any other fields that you have updated in the table above.

f) Please provide any other information about this facility that you would like MISO to consider for Variance Analysis.

11) Facility 27060 (MP)

a) Please update the table below, which is derived from MTEP21 Appendix A, with any proposed changes. When updating, please craft "Description" verbiage at approximately the same summary-level shown in the "Original" column of the table. There will be an opportunity to provide additional details below the table.

Facility ID	27060 – *Original*	27060 – *Updated*
Facility Type	TX	
From Sub	Iron Range 500/230kV	
To Sub		
Max kV	500	
Min kV	345	
Emerg. Rating	1200 MVA	
Expected ISD	6/1/2030	
Description	Add 2-345/500kV 1200MVA transformers (with 1 single phase spare on-site)	
Miles Upgrade		
Miles New		
Estimated Cost 2022$	$36,400,000	
Estimated Cost Nominal$	Not calculated in MTEP	

b) **Scope:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the scope of work for this facility (as summarized above in the "Description," "Miles Upgrade," "Miles New," or "Emerg. Rating" fields). For substation facilities, describe any scope changes along with the rationale; for existing substation modifications, include substation one-line drawings that depict the substation before the project and after the project with the proposed project modifications called out; for new substations, include substation one-line drawings that highlight the scope changes. For transmission line facilities, describe any scope changes along with the rationale; include a simplified transmission diagram that illustrates the scope changes.

c) **Schedule:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive delays in the schedule for energization of this facility (as shown above in "Expected ISD" field) that would cause a delay in the expected ISD for the entire LRTP Project.

d) **Cost:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the estimated cost for this facility (as shown above in the "Estimated Cost 2022$" field). Please update both the 2022$ and Nominal$ fields if documenting a change to the estimated cost.

e) Please provide additional details (cause, rationale, circumstances, etc.) about any other fields that you have updated in the table above.

f) Please provide any other information about this facility that you would like MISO to consider for Variance Analysis.

12) Facility 27061 (MP)

a) Please update the table below, which is derived from MTEP21 Appendix A, with any proposed changes. When updating, please craft "Description" verbiage at approximately the same summary-level shown in the "Original" column of the table. There will be an opportunity to provide additional details below the table.

Facility ID	27061 – *Original*	27061 – *Updated*
Facility Type	SUB	
From Sub	Iron Range 500/230kV	
To Sub		
Max kV	500	
Min kV		
Emerg. Rating	3000 A	
Expected ISD	6/1/2030	
Description	Add 5-position 500 kV ring bus (line to Dorsey, 500-230 TX, 500-345 TX, Cap Bank, 500-345 TX)	
Miles Upgrade		
Miles New		
Estimated Cost 2022$	$14,000,000	
Estimated Cost Nominal$	Not calculated in MTEP	

b) **Scope:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the scope of work for this facility (as summarized above in the "Description," "Miles Upgrade," "Miles New," or "Emerg. Rating" fields). For substation facilities, describe any scope changes along with the rationale; for existing substation modifications, include substation one-line drawings that depict the substation before the project and after the project with the proposed project modifications called out; for new substations, include substation one-line drawings that highlight the scope changes. For transmission line facilities, describe any scope changes along with the rationale; include a simplified transmission diagram that illustrates the scope changes.

c) **Schedule:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive delays in the schedule for energization of this facility (as shown above in "Expected ISD" field) that would cause a delay in the expected ISD for the entire LRTP Project.

d) **Cost:** Please provide additional details (cause, rationale, circumstances, etc.) about any substantive changes in the estimated cost for this facility (as shown above in the "Estimated Cost 2022$" field). Please update both the 2022$ and Nominal$ fields if documenting a change to the estimated cost.

e) Please provide additional details (cause, rationale, circumstances, etc.) about any other fields that you have updated in the table above.

f) Please provide any other information about this facility that you would like MISO to consider for Variance Analysis.

Northland Reliability Project

February 27, 2026

Jeremiah Doner
Director of Cost Allocation and Competitive Transmission
Midcontinent Independent System Operator, Inc.

RE: GRE and MP Response to Request for Information #1 for Variance Analysis on MTEP21 LRTP Project 03 Iron Range – Benton County – Big Oaks

Dear Mr. Doner,

With respect to MISO's RFI #1 for the Variance Analysis of the above-referenced project, we are pleased to provide the enclosed response from Minnesota Power ("MP") and Great River Energy ("GRE"). If you have any further questions or need clarification on any of the information provided in this response, please do not hesitate to contact either of us.

Sincerely,

Christian Winter	Matt Ellis
Manager, Regional Transmission Planning	*Director, Transmission Planning & Compliance*
Minnesota Power	Great River Energy

Attachment
NRP_Cost&ScheduleUpdates_FINAL.pdf

Northland Reliability Project

GREAT RIVER ENERGY | minnesota power

1. General Topics

a. If GRE and MP have summary materials that have been prepared to explain the respective variances that triggered Variance Analysis on the facilities that comprise LRTP Project 3, please provide them. (GRE and MP are not required to create summary materials, beyond those already provided, if they do not exist at this time.)

Response: GRE and MP appreciate the opportunity to provide MISO additional details on the cost and scope changes for the Northland Reliability Project ("Project") since MISO's approval on July 25, 2022. Additional details on each cost and scope change including background, drivers, and links to the Minnesota Public Utilities Commission's ("Commission") regulatory proceedings are detailed in the attached: *NRP_Cost&ScheduleUpdates_FINAL.pdf*

b. In this RFI #1, MISO will ask for the estimated cost of each individual facility in both 2022$ and in Nominal$. In the October 10, 2025, response to MISO's initial inquiry, GRE/MP explained how it converted the estimated costs to 2022$ as follows:

> *"Updated estimated costs are provided in 2022 dollars. Project cost estimates terms other than real $-2022 have been de-escalated to 2022 using 4% assumed inflation rate for labor and external contractor costs, as well as a 5.6% assumed inflation rate for materials. The amount of de-escalation per estimate line item is dependent on the project schedule's delivery or end date for that item."*
>
> Please confirm whether this explanation is still applicable, as well as add any clarifying statements that you wish for MISO to consider in relation to GRE/MP's internal escalation/deescalation methodology.

Response: This explanation is still applicable.

2.-12. Facility Tables

MISO instructions common to all facility tables: Please update the table below, which is derived from MTEP21 Appendix A, with any proposed changes. When updating, please craft "Description" verbiage at approximately the same summary-level shown in the "Original" column of the table. There will be an opportunity to provide additional details below the table.

Response: MP's and GRE's responses are provided below, in blue, for the tables and subsequent discussion of Scope, Schedule, Cost, and additional details.

Northland Reliability Project

GREAT RIVER ENERGY | minnesota power

2. Facility 27051 (GRE)

a. Table Updates

Facility ID	27051 – Original	27051 – DELETED. Combined with Facility 27053.
Facility Type	LN	
From Sub	Cassie's Crossing (aka, Big Oaks)	
To Sub	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W	
Max kV	345	
Min kV		
Emerg. Rating	3000 A	
Expected ISD	6/1/2030	
Description	Replace existing GRE single circuit 230kV transmission line with double circuit 345kV transmission line. Both lines will tie to Benton County.	
Miles Upgrade	12.5	
Miles New		
Estimated Cost 2022$	$48,800,000	
Estimated Cost Nominal$	Not calculated in MTEP	

b. Scope

This facility is being bundled with 27053 as a single transmission line facility.

c. Schedule

N/A

d. Cost

N/A

e. Additional details about table:

N/A

f. Additional information for MISO's Variance Analysis consideration:

N/A

Northland Reliability Project

GREAT RIVER ENERGY | minnesota power

3. Facility 27052 (GRE)

a. Table Updates

Facility ID	27052 – Original	27052 – DELETED Combined with Facility 27054.
Facility Type	LN	
From Sub	Sherco	
To Sub	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W	
Max kV	345	
Min kV		
Emerg. Rating	3000 A	
Expected ISD	6/1/2028	
Description	Replace existing Benton County-Sherco line to accommodate a rating greater than 3000 Amps. Including south deadend structure for new conductor. This line will tie to Benton County	
Miles Upgrade	7.3	
Miles New		
Estimated Cost 2022$	$25,000,000	
Estimated Cost Nominal$	Not calculated in MTEP	

b. Scope

This facility is being bundled with 27054 as a single transmission line facility.

c. Schedule

N/A

d. Cost

N/A

e. Additional details about table:

N/A

f. Additional information for MISO's Variance Analysis consideration:

N/A

Northland Reliability Project

GREAT RIVER ENERGY | minnesota power

4. Facility 27053 (GRE)

a. Table Updates

Facility ID	27053 – Original	27053 – Updated
Facility Type	LN	LN
From Sub	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W	Big Oaks
To Sub	Benton County	Cherry Park (Benton County)
Max kV	345	345
Min kV		
Emerg. Rating	3000 A	3000 A
Expected ISD	6/1/2030	6/1/2030
Description	Replace existing GRE single circuit 230kV transmission line with double circuit 345kV transmission line. One line will tie to Sherco and other to Cassie Crossing.	From Big Oaks to line crossing, replace existing GRE single circuit 230kV with double circuit 345kV transmission line. At line crossing, reconfigure to avoid crossing Benton-Sherco 345kV line. From line crossing to Cherry Park (Benton County), replace existing Benton-Sherco 345kV line with double circuit 345kV transmission line. A portion of new line will include underbuild of an existing 69kV line.
Miles Upgrade	12.5	25 (including mileage of original Facility 27051)
Miles New		N/A
Estimated Cost 2022$	$48,800,000	$139,871,000 (including cost of original Facility 27051)
Estimated Cost Nominal$	Not calculated in MTEP	N/A

b. Scope

This facility was combined with Facility ID 27051 to encompass the entirety of the transmission line between Cherry Park (Benton County) and the new Big Oaks (Cassie's Crossing) substation. Cherry Park is the name for the 345kV substation expansion at the Benton County Substation site. Big Oaks is the name of the new substation formerly referred to as Cassie's Crossing in the MTEP21 approval. The facility scope remains as a replacement of the existing transmission lines between Monticello/Sherco and Benton County with a double circuit 345kV line. A portion of this facility will also include an underbuild of an existing 69kV line on the double circuit 345kV structures – see Section 4.1.4.1 of *NRP_Cost&ScheduleUpdates_FINAL.pdf* for additional details.

For comparison, the original mileage of all MTEP Facility ID's included in this discussion of Updated Facility ID 27053 are compared to the updated mileage in the table below:

Miles Upgrade	Original	New (27053)
27051	12.5	25
27053	12.5	
TOTAL	**25**	**25**

c. Schedule

The current schedule remains with a target in-service date (ISD) of 6/1/2030.

d. Cost

Increased facility costs are attributed to several factors including:

- Transmission line specifications and market impacts – see Section 4.1 and 4.1.1,
- Increased future optionality – see Section 4.1.4.1,
- And asset retirement and permitting costs – see Section 4.1.4.

All referenced sections in "*NRP_Cost&ScheduleUpdates_FINAL.pdf.*"

For comparison, the original cost of all MTEP Facility ID's included in this discussion of Updated Facility ID 27053 are compared to the updated cost estimate in the table below:

Cost (2022$)	Original	New (27053)
27051	$48,800,000	$139,871,000
27053	$48,800,000	
TOTAL	**$97,600,000**	**$139,871,000**

e. Additional details about table:

N/A

f. Additional information for MISO's Variance Analysis consideration:

Please reference "*NRP_Cost&ScheduleUpdates_FINAL.pdf*" for additional details.

Northland Reliability Project

GREAT RIVER ENERGY | minnesota power

5. Facility 27054 (GRE)

a. Table Updates

Facility ID	27054 – Original	27054 – Updated
Facility Type	LN	LN
From Sub	Structure(s) at estimated GPS Coordinates: 45°27'37.5"N 93°53'32.5"W	Sherco
To Sub	Benton County	Cherry Park (Benton County)
Max kV	345	345
Min kV		
Emerg. Rating	3000 A	3000 A
Expected ISD	6/1/2028	6/1/2028
Description	Replace the existing Benton County-Sherco line to accommodate a rating greater than 3000 Amps. Including north deadend structure for new conductor. This line will tie to Cassie Crossing.	From Sherco to line crossing, replace the existing Benton County-Sherco single circuit 345 kV to accommodate a rating greater than 3000 Amps on double-circuit 345 kV capable structures. At line crossing, reconfigure to avoid crossing Benton to Big Oaks 345kV line (formerly 230kV to Monticello). A portion of new line will include underbuild of an existing 69kV line.
Miles Upgrade	14.1	21.4 (including mileage of original Facility 27052)
Miles New		
Estimated Cost 2022$	$47,400,000	$106,013,000 (including cost of original Facility 27052)
Estimated Cost Nominal$	Not calculated in MTEP	N/A

b. Scope

This facility was combined with Facility ID 27052 to encompass the entirety of the transmission line between Cherry Park (Benton County) and the Sherco Substation. Cherry Park is the name for the 345kV substation expansion at the Benton County Substation site. The facility scope remains as a replacement of the existing transmission lines between Sherco and Benton County with a higher capacity 345kV transmission line. This facility will be built as a single-circuit double-circuit capable 345kV transmission line; a portion of this facility will also include an underbuild of an existing 69kV line – see Section 4.1.4.1 of *NRP_Cost&ScheduleUpdates_FINAL.pdf* for additional details.

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For comparison, the original mileage of all MTEP Facility ID's included in this discussion of Updated Facility ID 27054 are compared to the updated mileage in the table below:

Miles Upgrade	**Original**	**New (27054)**
27052	14.1	21.4
27054	7.3	
TOTAL	**21.4**	**21.4**

c. Schedule

The current schedule remains with a target ISD of 6/1/2028.

d. Cost

Increased facility costs are attributed to several factors including:

- Transmission line specifications and market impacts – see Section 4.1 and 4.1.1,
- Increased future optionality – see Section 4.1.4.1,
- And asset retirement and permitting costs – see Section 4.1.4.

All referenced sections in "*NRP_Cost&ScheduleUpdates_FINAL.pdf.*"

For comparison, the original cost of all MTEP Facility ID's included in this discussion of Updated Facility ID 27054 are compared to the updated cost estimate in the table below:

Cost (2022$)	**Original**	**New (27053)**
27052	$47,400,000	$106,013,000
27054	$25,000,000	
TOTAL	**$72,400,000**	**$106,013,000**

e. Additional details about table:

N/A

f. Additional information for MISO's Variance Analysis consideration:

Please reference "*NRP_Cost&ScheduleUpdates_FINAL.pdf*" for additional details.

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6. Facility 27055 (GRE)

a. Table Updates

Facility ID	27055 – Original	27055 – Updated
Facility Type	SUB	SUB
From Sub	Benton County	Cherry Park (Benton County)
To Sub		
Max kV	345	345
Min kV		
Emerg. Rating	3000 A	3000 A
Expected ISD	6/1/2030	6/1/2030
Description	Add 345kV 7-position breaker-and-a-half bus with 2 transformer positions and 5 line positions (one an existing modification), with two line connected 70MVAr shunt reactors on Iron Range lines, and modify 230kV position for one 230/345kV transformer	Add 345kV 7-position breaker-and-a-half bus with 2 transformer positions and 5 line positions (one an existing modification), with two bus connected 60MVAr shunt reactors, and modify 230kV position for one 230/345kV transformer going to Benton County. Cherry Park is at the Benton County Substation site but a separate fenced area due to physical site constraints.
Miles Upgrade		
Miles New		
Estimated Cost 2022$	$25,500,000	$45,152,000
Estimated Cost Nominal$	Not calculated in MTEP	N/A

b. Scope

The overall scope of the Cherry Park (Benton County) substation facility remains the same. The expansion of the Benton County 345/230 kV Substation is required to accommodate the new 345 kV and upgraded lines connecting to the Cuyuna, Big Oaks, and Sherco substations. Due to physical constraints at the existing Benton County Substation site a new fenced area was required – referred to as Cherry Park. Additionally, to address issues identified in detailed design electrical studies (delayed current zero crossing) the size and configuration of the Cherry Park shunt reactors were modified See Section 4.2.3.1 of *NRP_Cost&ScheduleUpdates_FINAL.pdf* for additional details.

c. Schedule

The current schedule remains with a target ISD of 6/1/2030.

d. Cost

Increased facility costs are attributed to several factors including:

- Substation equipment market impacts – see Section 4.1.2.1 and 4.2.3.1,
- Substation scope and configuration updates identified during detailed design – see Section 4.2.3.1,

All referenced sections in "*NRP_Cost&ScheduleUpdates_FINAL.pdf.*"

e. Additional details about table:

N/A

f. Additional information for MISO's Variance Analysis consideration:

Please reference "*NRP_Cost&ScheduleUpdates_FINAL.pdf*" for additional details.

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7. Facility 27056 (MP)

a. Table Updates

Facility ID	27056 – Original	27056 – Updated
Facility Type	LN	LN
From Sub	Benton County	Cherry Park (Benton County)
To Sub	Riverton 230/115kV	Cuyuna
Max kV	345	345
Min kV		
Emerg. Rating	3000 A	3000 A
Expected ISD	6/1/2030	6/1/2030
Description	Construct new 345kV double circuit transmission line	Construct new 345kV double circuit transmission line, including the following relocations and realignments to enable siting of the new facility in or adjacent to existing rights-of-way per State of MN routing criteria: 3.5 miles of MR 230kV Line relocation and retermination at Benton County, 5.1 miles rebuild of MR/BP 230kV/69kV on double circuit structures, 4.5 miles rebuild of MR/RW 230kV/69kV on double circuit structures, 4.3 miles rebuild of 115kV 12 Line, 6.3 miles rebuild of 115kV 13 Line, and 7 targeted realignments of MR 230kV Line. Also includes relocation of existing Riverton 115/34kV Substation and equipment into Riverton 230/115kV Substation, upgrades to Riverton 230/115 kV Substation, and retermination of existing transmission lines at Riverton 230/115 kV Substation to enable siting of the new double-circuit 345kV line in or adjacent to existing rights-of-way per State of MN routing criteria.
Miles Upgrade		23
Miles New	78	68
Estimated Cost 2022$	$312,000,000	$458,932,000
Estimated Cost Nominal$	Not calculated in MTEP	N/A

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b. Scope

This facility combined with Facility ID 27058 make up the primary new transmission line components of the Project. The Cherry Park (Benton County) to Cuyuna to Iron Range double circuit 345kV has a mid-point series compensation station at Cuyuna and as a result the facilities are split into a south segment and a north segment. This facility is the south segment which connects Cherry Park (Benton County) and Cuyuna. The overall scope and purpose of this facility is consistent with MISO's approval. Major scope updates since MISO's original approval include the following:

- On February 28, 2025, the Minnesota Public Utilities Commission approved the route for the Project. The Commission has authority to determine the route which best meets the State's established routing criteria. The route for this facility is approximately ten miles shorter than MISO's approved length – see Section 4.1.3.1 of *NRP_Cost&ScheduleUpdates_FINAL.pdf* for additional details.
- The Commission approved route for this facility includes approximately 20-miles of existing transmission asset co-locations as well as the relocation of an existing substation to make room for siting the new transmission line facility. Co-location, in this situation, is the replacement of two existing single circuit transmissions lines with a new double-circuit (common tower) transmission line (e.g. an existing single-circuit 230kV and single-circuit 115kV are both removed and rebuilt on a double-circuit 230/115kV transmission line). Co-locating assets frees existing transmission right-of-way which can then be repurposed for siting the Project. The Commission approved route includes four major co-location areas to route the Project through pinch-points. All co-locations meet NERC reliability standards under common tower contingencies ("P7"). See Section 4.2.1 and related subsections of *NRP_Cost&ScheduleUpdates_FINAL.pdf* for additional details.
- The Commission approved route for this facility also includes approximately 3-miles of existing transmission line realignments and other route refinements identified during the Commission's route permit process. Realignment, in this situation, is the shifting of an existing transmission line's centerline (removal and replacement) to route the Project through a pinch point. Realignments are used in lieu of more expensive and less resilient transmission line crossings to avoid residential displacement. See Sections 4.1.3.2 and 4.2.2 of *NRP_Cost&ScheduleUpdates_FINAL.pdf* for additional details.
- The northern termination point for this facility has moved from the existing Riverton 230/115kV substation to an electrically equivalent expansion approximately two-miles north due to physical site constraints. Additional details are contained under Facility 27057 and in Section 4.1.2.2 of *NRP_Cost&ScheduleUpdates_FINAL.pdf*.

c. Schedule

The current schedule remains with a target ISD of 6/1/2030.

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d. Cost

The net increase in facility costs is attributed to several factors including the scope changes described in response to (a) as well as:

- Transmission line specifications and market impacts – see Section 4.1,
- Construction optimization – see Section 4.2.3.2
- And asset retirement and permitting costs – see Section 4.1.4.

All referenced sections in "*NRP_Cost&ScheduleUpdates_FINAL.pdf.*"

e. Additional details about table:

N/A

f. Additional information for MISO's Variance Analysis consideration:

Please reference "*NRP_Cost&ScheduleUpdates_FINAL.pdf*" for additional details.

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8. Facility 27057 (MP)

a. Table Updates

Facility ID	27057 – Original	27057 – Updated
Facility Type	SC	SC
From Sub	Riverton 230/115kV	Cuyuna
To Sub		
Max kV	345	345
Min kV		
Emerg. Rating	3000 A	3000 A
Expected ISD	6/1/2030	6/1/2030
Description	Add 4-345kV series capacitor bank groups (2 in series for each circuit) with protective bypass equipment. Impedance of series capacitor bank will be approximately 60% compensation of line	Construct new 6-position 345 kV breaker-and-a-half bus near the existing Riverton 230/115kV Substation. Add 4-345kV series capacitor banks (1 for each line segment going north and south) with protective bypass equipment. Impedance of series capacitor bank will be approximately 52% compensation of line Cuyuna is approximately 2 miles from the existing Riverton 230/115 kV Substation site due to physical site constraints and land availability.
Miles Upgrade		
Miles New		
Estimated Cost 2022$	$80,000,000	$116,436,000
Estimated Cost Nominal$	Not calculated in MTEP	N/A

b. Scope

The overall scope of the Cuyuna series compensation station facility remains the same as the series compensation station facility originally approved by MISO. The location was shifted approximately 2 miles north of the existing Riverton 230/115kV substation to remain near the electrical midpoint of the new 345kV lines, because the existing Riverton Substation site was highly constrained had insufficient space to add this new station. See Section 4.1.2.2 of *NRP_Cost&ScheduleUpdates_FINAL.pdf* for additional details. The percent compensation for the series capacitors was also optimized based on detailed design and performance studies, considering the impedance of the selected transmission line conductor and the impact of the series capacitors on transmission line maximum continuous operating voltage.

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The breaker-and-a-half bus included between the series capacitor segments at the Cuyuna Substation facilitates future expandability and connections, like the proposed Maple River – Cuyuna 345 kV Line that is included with the LRTP Tranche 2.1 portfolio (see LRTP Project #20). Additionally, to address issues identified in detailed design electrical studies (delayed current zero crossing), bus-connected shunt reactors were added to the Cuyuna Substation. This necessitated expanding the substation from a 4-position ring bus to a 6-position breaker-and-a-half configuration. See Section 4.2.3.1 of *NRP_Cost&ScheduleUpdates_FINAL.pdf* for additional details.

c. Schedule

The current schedule remains with a target ISD of 6/1/2030.

d. Cost

Increased facility costs are attributed to several factors including:

- Substation equipment market impacts – see Section 4.1.2.1 and 4.2.3.1,
- Substation scope and configuration updates identified during siting and detailed design – see Section 4.1.2.2 and 4.2.3.1

All referenced sections in "*NRP_Cost&ScheduleUpdates_FINAL.pdf.*"

e. Additional details about table:

N/A

f. Additional information for MISO's Variance Analysis consideration:

N/A

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9. Facility 27058 (MP)

a. Table Updates

Facility ID	27058 – Original	27058 – Updated
Facility Type	LN	LN
From Sub	Riverton 230/115kV	Cuyuna
To Sub	Iron Range 500/230kV	Iron Range
Max kV	345	345
Min kV		
Emerg. Rating	3000 A	3000 A
Expected ISD	6/1/2030	6/1/2030
Description	Construct new 345kV double circuit transmission line	Construct new 345kV double circuit transmission line, including the following relocations and realignments to enable siting of the new facility in or adjacent to existing rights-of-way per State of MN routing criteria: 19.2 miles of 115kV 11 Line and 20.3 miles of 115kV 92 Line
Miles Upgrade		40
Miles New	78	66
Estimated Cost 2022$	$312,000,000	$407,612,000
Estimated Cost Nominal$	Not calculated in MTEP	N/A

b. Scope

This facility combined with Facility ID 27056 make up the primary new transmission line components of the Project. The Cherry Park (Benton County) to Cuyuna to Iron Range double circuit 345kV has a mid-point series compensation station at Cuyuna and as a result the facilities are split into a south segment and a north segment. This facility is the north segment which connects Iron Range and Cuyuna. The overall scope and purpose of this facility is consistent with MISO's approval. Scope updates since MISO's original approval include:

- On February 28, 2025, the Minnesota Public Utilities Commission approved the route for the Project. The Commission has authority to determine the route which best meets the State's established routing criteria. The route for this facility is approximately 12-miles shorter than MISO's approved length – see Section 4.1.3.1 of *NRP_Cost&ScheduleUpdates_FINAL.pdf* for additional details.
- The Commission approved route for this facility includes approximately 40-miles of existing transmission asset co-locations. Co-location, in this situation, is the replacement of two existing single circuit transmissions lines with a new double-circuit (common tower) transmission line (e.g. an existing single-circuit 230kV and single-circuit 115kV are both removed and rebuilt on a double-circuit 230/115kV transmission line). Co-locating assets frees existing transmission right-of-way which can then be repurposed

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for siting the Project. All co-locations meet NERC reliability standards under common tower contingencies (“P7”). See Section 4.2.1 and subsections of *NRP_Cost&ScheduleUpdates_FINAL.pdf* for additional details.

- The Commission approved route for this facility also includes multiple existing transmission line realignments and other route refinements identified during the Commission’s route permit process. Realignment, in this situation, is the shifting of an existing transmission line’s centerline (removal and replacement) to route the Project through a pinch point. Realignments are used in lieu of more expensive and less resilient transmission line crossings to avoid residential displacement. See Sections 4.1.3.2 and 4.2.2 of NRP_Cost&ScheduleUpdates_FINAL.*pdf* for additional details.
- The southern termination point for this facility has moved geographically from the existing Riverton 230/115kV substation to an electrically equivalent location for the Cuyuna Substation approximately two miles north due to physical site constraints. Additional details are contained under Facility 27057 and in Section 4.1.2.2 of *NRP_Cost&ScheduleUpdates_FINAL.pdf*.

c. Schedule

The current schedule remains with a target ISD of 6/1/2030.

d. Cost

The net increase in facility costs is attributed to several factors including the scope changes described in response to (a) as well as:

- Transmission line specifications and market impacts – see Section 4.1,
- Construction optimization – see Section 4.2.3.2
- And asset retirement and permitting costs – see Section 4.1.4.

All referenced sections in “*NRP_Cost&ScheduleUpdates_FINAL.pdf.”*

e. Additional details about table:

N/A

f. Additional information for MISO’s Variance Analysis consideration:

Please reference “*NRP_Cost&ScheduleUpdates_FINAL.pdf”* for additional details.

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10. Facility 27059 (MP)

a. Table Updates

Facility ID	27059 – Original	27059 – Updated
Facility Type	SUB	SUB
From Sub	Iron Range 500/230kV	Iron Range 500/230kV
To Sub		
Max kV	345	500
Min kV		345
Emerg. Rating	3000 A	3000 A substation 1500 MVA transformer
Expected ISD	6/1/2030	6/1/2030
Description	Add 4-position 345kV ring bus (expandable to breaker-and-a-half bus) for 2-345/500kV transformer positions and 2 line positions (includes 2-345 kV shunt reactors on lines to Benton, est. 50 MVAR each)	Expand existing Iron Range 500kV Substation to establish a 5-position 500 kV ring bus (line to Dorsey, 500-230 TX, 500-345 TX, Cap Bank, 500-345 TX), add 2-345/500kV 1200MVA transformers (with 1 single phase spare on-site), and add 4-position 345kV breaker-and-a-half bus for 2-345/500kV transformer positions and 2-345kV line positions (includes 2-345 kV bus connected shunt reactors, 60 MVAR each). Includes rerouting of existing 230kV and 115kV lines around substation expansion area.
Miles Upgrade		
Miles New		
Estimated Cost 2022$	$20,000,000	$115,879,000 (including cost of original Facilities 27060 and 27061)
Estimated Cost Nominal$	Not calculated in MTEP	N/A

b. Scope

The overall scope of the Iron Range facilities remains the same, this change represents the consolidation of the MTEP Facility ID's for the three Iron Range facilities (27059, 27060, and 27061) into a single MTEP Facility ID for more concise discussion and reporting. As originally proposed, the Iron Range 500kV is expanding to a full ring bus with breakers (formerly Facility ID 27061) to accommodate the connection of additional 500/345kV transformers (formerly Facility ID 27060), along with an expansion to accommodate a new 345kV substation yard. To address issues identified in detailed design electrical studies (delayed current zero crossing), the size and configuration of the Iron Range shunt reactors was modified. This necessitated

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expanding the substation from a 4-position ring bus to a 6-position breaker-and-a-half configuration. See Section 4.2.3.1 of *NRP_Cost&ScheduleUpdates_FINAL.pdf* for additional details.

c. Schedule

The current schedule remains with a target ISD of 6/1/2030.

d. Cost

Increased facility costs are attributed to several factors including:

- Substation equipment and market impacts – see Section 4.1.2.1 and 4.2.3.1,
- Substation scope and configuration updates identified during detailed design – see Section 4.2.3.1

All referenced sections in "*NRP_Cost&ScheduleUpdates_FINAL.pdf.*"

For comparison, the original cost of all MTEP Facility ID's included in this discussion of Updated Facility ID 27059 are compared to the updated cost estimate in the table below:

Cost (2022$)	**Original**	**New (27053)**
27059	$20,000,000	$115,879,000
27060	$36,400,000	
27061	$14,000,000	
TOTAL	**$70,400,000**	**$115,879,000**

e. Additional details about table:

N/A

f. Additional information for MISO's Variance Analysis consideration:

Please reference "NRP_Cost&ScheduleUpdates_FINAL.pdf" for additional details.

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11. Facility 27060 (MP)

a. Table Updates

Facility ID	27060 – Original	27060 – DELETED Combined with Facility 27059.
Facility Type	TX	
From Sub	Iron Range 500/230kV	
To Sub		
Max kV	500	
Min kV	345	
Emerg. Rating	1200 MVA	
Expected ISD	6/1/2030	
Description	Add 2-345/500kV 1200MVA transformers (with 1 single phase spare on-site)	
Miles Upgrade		
Miles New		
Estimated Cost 2022$	$36,400,000	
Estimated Cost Nominal$	Not calculated in MTEP	

b. Scope

This facility was combined with 27059 as a single substation facility.

c. Schedule

N/A

d. Cost

N/A

e. Additional details about table:

N/A

f. Additional information for MISO's Variance Analysis consideration:

N/A

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12. Facility 27061 (MP)

a. Table Updates

Facility ID	27061 – Original	27061 – DELETED Combined with Facility 27059.
Facility Type	SUB	
From Sub	Iron Range 500/230kV	
To Sub		
Max kV	500	
Min kV		
Emerg. Rating	3000 A	
Expected ISD	6/1/2030	
Description	Add 5-position 500 kV ring bus (line to Dorsey, 500-230 TX, 500-345 TX, Cap Bank, 500-345 TX)	
Miles Upgrade		
Miles New		
Estimated Cost 2022$	$14,000,000	
Estimated Cost Nominal$	Not calculated in MTEP	

b. Scope

This facility was combined with 27059 as a single substation facility.

c. Schedule

N/A

d. Cost

N/A

e. Additional details about table:

N/A

f. Additional information for MISO's Variance Analysis consideration:

N/A

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Project Update Report

Background and Justification for Updates to Project Scope and Cost through State Regulatory Approvals

October 2025

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APPENDICES

1 EXECUTIVE SUMMARY

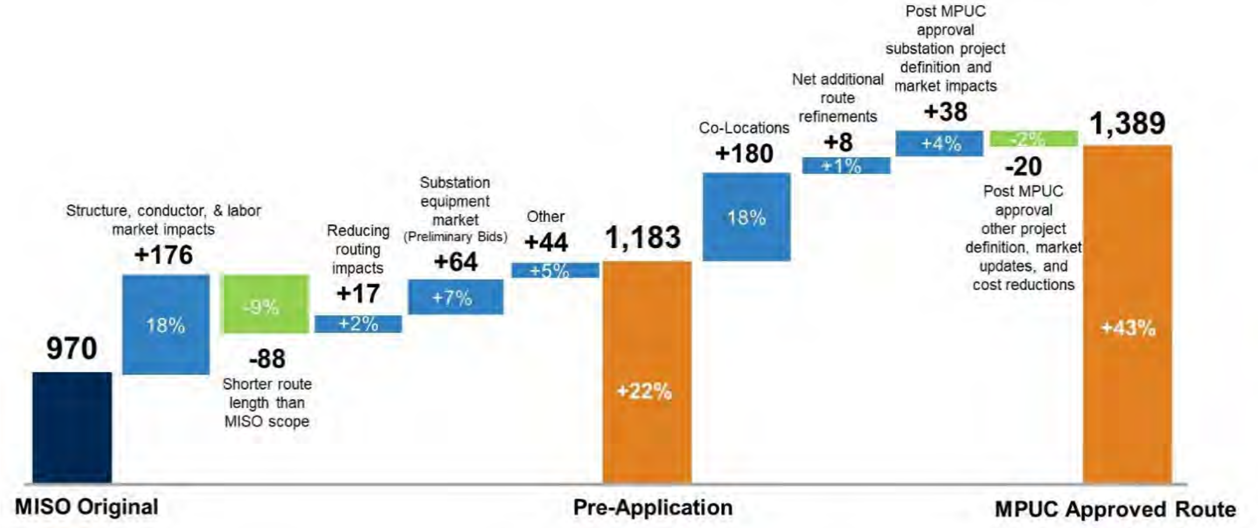
Pursuant to Attachment FF of the Midcontinent Independent System Operator, Inc.'s ("MISO") Tariff, Minnesota Power ("MP") and Great River Energy ("GRE") have provided updated costs, facility descriptions, and in-service dates to MISO for MISO Long-Range Transmission Plan ("LRTP") Project #3, the Northland Reliability Project, following the Minnesota Public Utilities Commission's ("MPUC" or "Commission") approval of the combined Certificate of Need ("CON") and Route Permit ("RP") Application (hereafter, the "Application or the "CON/RP Application") on February 28, 2025.[1] MP and GRE respectfully request MISO to find that these scope and cost updates are reasonable, prudent, and necessary for the Northland Reliability Project, and to incorporate them into the MISO-approved scope of LRTP Project #3.

The Northland Reliability Project ("Project") involves the construction of an approximately 180-mile double-circuit 345 kilovolt ("kV") high-voltage transmission line between Grand Rapids (northern Minnesota) and Becker (outside the Twin Cities of Minnesota). The Project was studied, reviewed, and ultimately approved as part of the LRTP Tranche 1 Portfolio by MISO's Board of Directors in July 2022. The Project will ensure that the power grid in northern and central Minnesota continues to operate safely and reliably as energy resources in Minnesota and the region continue to evolve.

MISO's July 2022 approval estimated the Project to cost $970 million ($-2022) and included a need by date of June 2030. The MISO approved Project cost estimate was developed between late 2021 and early 2022. The current cost estimate for the Project as of mid-2025 is $1,389 million ($-2022), an approximate 43 percent increase from MISO's approved cost estimate. Figure 1-1 illustrates the major changes impacting the Project's cost from the MISO original approved cost estimate to the cost estimate included by MP and GRE in the CON/RP Application, to the current baseline cost estimate updated to reflect the Commission's final route decision.

[1] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, ORDER GRANTING CERTIFICATE OF NEED AND ISSUING ROUTE PERMIT (Feb. 28, 2025) (eDocket No. 20252-215918-01). A full copy of the Commission's approval order is contained in Appendix D.

Figure 1-1 – Northland Reliability Project Cost Estimate Change
All values in millions $-2022 - mid-level estimates



The increased cost from MISO's approved cost estimate is generally attributed to:

- **25 percent** inflation and market factors;
- **12 percent** routing factors, including the Commission's final approved route;
- **6 percent** scope refinements and other factors, including future optionality, updated substation facility scopes, transmission facility asset retirements, and other costs not considered in the original MISO approved estimate

The Project's MISO approved cost estimate was developed during the early stages and without full knowledge of the impacts of historic inflation, supply chain disruptions and labor market spikes that took place since 2021. Without this level of market volatility the Project cost increase attributable to routing-related impacts, scope refinements, and other factors would be within the 25 percent variance analysis threshold established in the MISO Tariff.[2] This report provides detailed discussion and justification for the increase to the Project cost estimate, which are summarized below and discussed in Section 4.

Inflation and Market Factors: Since MISO's original development of the LRTP Tranche 1 projects and the estimated costs in late 2021, market pressures have had significant impacts on the cost of delivering high-voltage transmission projects. Much of this impact is due to global and domestic supply chain pressures stemming from the COVID-19 pandemic, but more recently the global electric utility market and supply chain have been significantly impacted by geopolitical events such as the Russia-Ukraine war starting in second quarter 2022. In addition, market impacts are driven by high demand for engineering, labor, materials, and equipment both domestically and internationally.

[2] MISO FERC Electric Tariff, Attachment FF (Transmission Expansion Planning Protocol) (93.0.0) § IX, *available at* https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/.

Compounding the market impacts, the inflation rate since the Project estimate was developed has been at a historic high.[3]

Market factors resulted in a total Project cost increase of approximately 25 percent since the original estimate. Of this 25 percent, approximately 7 percent is driven by increased substation costs, specifically major equipment costs such as transformers, reactors, breakers, and series compensation, and 18 percent is driven by market increases in transmission line material (steel structures, conductors, and foundations) and construction labor. All current Project costs are based on secured vendor and contractor bids evaluated through a competitive bidding process.

The market related cost increases experienced by MP and GRE for the Project are consistent with the Handy-Whitman Index[4] and MISO Cost Estimation Guide. The Handy-Whitman Index of Public Utility Costs for the North Central Region from January 2022 to January 2025 shows a 29 percent increase in total transmission plant and a 28 percent increase in substation equipment. Consistently, the MISO Cost Estimation Guide from MISO Transmission Expansion Plan 2022 ("MTEP22") to MTEP25 has an approximately 15 percent increase in Minnesota exploratory double-circuit 345 kV line costs and a 37 percent increase in 345 kV substations. The Project's current cost for double-circuit 345 kV of $5.4 million per mile ($-2022) escalated to 2025 dollars is $5.9 million per mile ($-2025) - below MISO's MTEP25 Cost Estimation Guide value of $6.2 million per mile ($-2025).[5]

The inflationary and market pressures experienced by the Project can be expected to similarly impact all Tranche 1 projects.

Routing Factors: The projected route that formed the basis of the MISO cost estimate has changed substantially since the MISO Board approved the Project in 2022. The Project's final route was developed over multiple iterations of desktop analysis, survey, community engagement, and regulatory hearings. The final MPUC approved route resulted in a cost increase of approximately 12 percent from MISO's approved cost estimate. While the final MPUC approved route reduced the length of the proposed double-circuit 345 kV line by approximately 16 miles, it also added approximately 63 miles[6] of co-located facilities, routing the Project with existing rebuilt or modified transmission line facilities, including several realignments of existing transmission lines. The final Commission-approved route results in a net Project cost increase of $180 million ($-2022). The Commission's order requires MP and GRE to seek opportunities to reduce

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3 https://www.bls.gov/charts/consumer-price-index/consumer-price-index-by-category-line-chart.htm

4 The Handy-Whitman Index is a cost index that tracks the price of construction and equipment for electric utilities. It's published by Whitman, Requardt & Associates, LLP semi-annually, on January 1 and July 1.

5 https://cdn.misoenergy.org/MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP25337433.pdf

6 Mileage is the total of all lines. E.g. two (count) existing parallel 10 mile single-circuit transmission lines being rebuilt on a common 10 mile double-circuit structure is represented as 20 miles.

Project costs[7] and requires MP to justify any Project costs above $1.21 billion, or 125 percent of the original MISO approved Project cost.[8]

Scope Refinements and Other Factors: Since MISO's July 2022 approval, the Project scope and facility descriptions have been updated to reflect detailed engineering and scope refinement to meet MISO's stated reliability need, the Commission's approved route, and the Commission's approved Project scope. All facility changes are electrically equivalent to MISO's original approved scope. In addition to the routing factors discussed above, the primary updates to the Project scope are:

- **Future optionality:** Benton County – Sherco 345 kV transmission line facility updated from single-circuit 345 kV to single-circuit on double-circuit capable 345 kV structures to accommodate a future 345 kV circuit when conditions warrant.
- **Mid-point series compensation station:** Moved from being located at MP's existing Riverton Substation property to a few miles north due to routing and siting constraints. Series compensation station renamed to Cuyuna.
- **Substation configurations:** Reactor sizes updated from 70 megavolt-amperes reactive ("MVAR") line-connected at two substations to 60 MVAR bus-connected at three substations to mitigate an electromagnetic transient reliability issue identified with the original MISO approved configuration. In addition to configuration changes necessary to accommodate the reactive power needs, substation scopes were updated to address site constraints for each substation, including splitting the Benton County 345 kV Substation into two separate but adjacent substation yards, with the new 345 kV yard being named Cherry Park.

Cost Containment: GRE and MP have taken steps to control costs as reflected in the current cost estimate and going forward including:

- Competitively bidding all major contracts,
- Arranging for earlier delivery of some materials, when appropriate, to minimize costs and/or mitigate tariff impacts,
- Providing contractor incentives to reduce costs below the current baseline costs, where appropriate,
- Scheduling wetland work during frozen conditions to save matting costs, and
- Early engagement with general contractor prior to construction to optimize design and construction efficiencies, such as:
    - Matting procurement plan and usage analysis netted savings of $20 million, and
    - Pole/foundation optimization analysis to reduce costs.

In-service date: The Project's in-service date is June 2030 – unchanged from MISO's approved need date. GRE and MP, from the beginning have taken steps to meet MISO's

[7] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, ORDER GRANTING CERTIFICATE OF NEED AND ISSUING ROUTE PERMIT at Order Point 8 (Feb. 28, 2025) (eDocket No. 20252-215918-01). A full copy of the Commission's approval order is contained in Appendix D.

[8] Id. at Order Point 3

need date and secure contractors and materials to avoid scarcity pricing. GRE and MP, in partnership with construction contractor(s), are accommodating the increased project scope of co-locations without delaying the in-service date. With the complex routing constraints and modifications due to the Commission-approved route, GRE and MP took detailed looks at outage constraints to develop a construction sequence to minimize impact to the existing system during construction.

Actions Requested of MISO by MP and GRE:
MP and GRE respectfully request MISO find that the scope and cost changes are reasonable, prudent, and necessary for the Project, and to incorporate them into the MISO-approved scope of LRTP Project #3. GRE and MP request that MISO revise the project baseline cost at $1,389 million ($-2022) and set a new variance analysis threshold at 13% ($1,564 million) - consistent with the Project's contingency established via the risk register.[9] As a mitigation plan, GRE and MP agree to provide MISO regular updates of project costs, scope, and schedule. In addition, GRE and MP are willing to provide MISO materials provided to the Commission to justify any project expenditures over $1,210 million (MISO original approved cost + 25%).

GRE and MP continue to look for opportunities to further reduce costs from the baseline and mitigate any additional cost impacts from tariffs or additional supply chain pressures, as directed by the MPUC and in accordance with good utility practice. GRE and MP are committed to safely energizing the Northland Reliability Project in 2030 on budget.

[9] The risk register is a line-item listing and cost contingency of prudent risks and unknowns that exist at each stage of the Project - additional details provided in Section 4.2.4.

2 OVERVIEW

The Project, also known as MISO LRTP Project #3, is a joint transmission project between MP and GRE that was approved by MISO in July 2022 as part of MTEP21. On February 28, 2025, the MPUC granted a CON and RP for the Project.[10] Pursuant to the MISO Tariff, MP and GRE are required to submit regular updates to MISO Appendix A, which publicly lists the description, costs, expected in-service date, and other details for all MISO-approved transmission projects. This document provides a detailed description of changes in the scope and cost of the Project between MISO's original 2022 approval and the Project team's updated cost estimate following the Commission's approval of the Project and its final route.

2.1 Background

The Project as originally proposed by MP and GRE in the CON/RP Application includes the construction of approximately 180 miles of new double-circuit 345 kV high-voltage transmission line, replacement of certain existing high-voltage transmission lines, and other improvements to the power grid in Minnesota, from the Grand Rapids area in Itasca County to the Becker area in Sherburne County.

The Project was studied, reviewed, and ultimately approved as part of the LRTP Tranche 1 Portfolio by the MISO's Board of Directors in July 2022 as part of its annual MTEP21 report. The Project will ensure that the power grid in northern and central Minnesota continues to operate safely and reliably as energy resources in Minnesota and the region continue to evolve. The Project, shown in Figure 2-1, consists of two major segments:

1. Segment One: Construction of a new, approximately 140-mile long, double-circuit 345 kV transmission line connecting the existing Iron Range Substation, a new Cuyuna Series Compensation Station located near the existing Riverton Substation, and the existing Benton County Substation, including an expansion area now referred to as Cherry Park, and

2. Segment Two: Replacement of two existing transmission lines, including replacing an approximately 20-mile 230 kV line with two 345 kV circuits from the Benton County Substation to the new Big Oaks Substation (originally referred to as the "Cassie's Crossing" Substation in MTEP21) along existing transmission corridors on double-circuit 345 kV structures; and replacing an approximately 20-mile 345 kV line from the Benton County Substation to the existing Sherco Substation in Sherburne County along existing transmission corridors using double-circuit capable 345 kV structures.

[10] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, ORDER GRANTING CERTIFICATE OF NEED AND ISSUING ROUTE PERMIT (Feb. 28, 2025) (eDocket No. 20252-215918-01). A full copy of the Commission's approval order is contained in Appendix D.

The Project also involves the following improvements to the power grid:

1. Expansion of the existing Iron Range Substation, located near Grand Rapids, and expansion of the existing Benton County Substation (including the Cherry Park Substation), located near St. Cloud, and rerouting existing transmission lines at the Iron Range and Benton County Substations; and

2. Construction of a new Cuyuna Series Compensation Station near the existing Riverton Substation and rerouting existing transmission lines in the Riverton area.

Figure 2-1: Northland Reliability Project Overview Map[11]

[11] Detailed parcel-level route maps available at https://northlandreliabilityproject.com/maps/

2.2 MISO's 2021 Approval

On July 25, 2022, MISO approved the LRTP Tranche 1 Portfolio, which includes the Project, referred to as LRTP#3, as part of the MTEP21. The MISO approved Project scope included:

- Construction of a new 156 mile double circuit 345 kV line from MP's existing Iron Range Substation to a new midpoint series compensation station at MP's existing Riverton Substation to GRE's existing Benton County Substation,
- An upgrade of GRE's existing 25 mile single-circuit 230 kV line between the Benton County Substation and Big Oaks Substation (formerly referred to as Cassie's Crossing) to double circuit 345 kV,
- An upgrade of GRE's existing 21.4 mile 345 kV line between the Benton County Substation and Sherco Substation, including reconfiguration of the line with the proposed Benton County – Big Oaks 345 kV line to eliminate an existing line crossing,
- Construction of a new mid-point series compensation station at MP's existing Riverton Substation, and
- Upgrades of MP's Iron Range 500 kV Substation and GRE's Benton County 345 kV Substation to accommodate the new 345 kV lines, including 500/345 kV transformers at Iron Range Substation and 345 kV shunt reactors at Iron Range and Benton County.

MISO estimated the Project to cost $970 million ($-2022) at the time of MISO Board approval in 2022. The MISO project cost estimate was developed based on the original facility descriptions, which were based on conceptual project information and prior to transmission line and substation engineering, detailed design electrical studies, and route development. The MISO approved cost estimate was developed in late 2021 with consideration from MISO's MTEP22 Cost Estimation Guide and with input from recent construction actual costs from MP and GRE, including the Great Northern Transmission Line[12] and CapX2020 projects,[13] all of which were constructed and placed into service prior to June 1, 2020. MISO listed the Project need-by date as June 1, 2030.

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[12] *Route Permit Application of Minnesota Power for the Great Northern Transmission Line*, Docket No. E-015/TL-14-21. *Project website available at*, [Great Northern Transmission Line].

[13] *In the Matter of the Application of Great River Energy, Northen States Power Company (d/b/a Xcel Energy) and Others for Certificates of Need for the CapX 345-kV Transmission Projects,* Docket Nos. ET-2-E-002, *et al.*/CN-06-1115. *Project website available at*, [Projects - Grid North Partners].

3 REGULATORY PROCEDURAL HISTORY

3.1 Prior to Filing Application with the Commission

August 1, 2022 – MP and GRE submitted a Notice of Intent to Construct, Own, Operate, and Maintain the Project ("Notice of Intent") to the Commission as required under Minnesota law.[14] The statute in effect at the time required that the Certificate of Need application for the Project be filed within 18 months from the filing of the Notice of Intent.

Following the Notice of Intent, MP and GRE began developing the combined Certificate of Need and Route Permit Application to file with the Commission. For development of the Route Permit portion of the Application, MP and GRE used a multi-stage, interactive process to identify a Proposed Route that focused on the use of existing high-voltage transmission line or other existing rights-of-way. This process was intended to identify a Proposed Route that met the objectives of the Project along with minimizing impacts to the environment in conformance with Minnesota's routing considerations. The iterative process started with the development of an initial study area for evaluation for the Project. This study area was then refined two additional times into a Route Corridor and Preliminary Route before the Applicants finalized the Proposed Route.

To gather feedback from a variety of stakeholders on the development of the Proposed Route, the Project team prepared a public engagement plan in late summer 2022 that consisted of several engagement methods. Public and stakeholder engagement opportunities included six in-person stakeholder workshops, virtual self-guided public open houses, seven in-person "route corridor" open houses, six in-person "preliminary route" open houses, direct mailings, social media posts, a dedicated email and hotline to field questions and comments, an interactive online comment map, a Project website, detailed maps that could be downloaded and printed from the Project website, and mailed Project information packets. The Project team also had regular discussions with local, state, federal, and tribal governments and agencies throughout the route development process. Throughout this process, MP and GRE incorporated stakeholder feedback throughout each stage of route development to refine the Proposed Route.

In light of the Minnesota statutory considerations and preference for following existing transmission line rights-of-way and other linear infrastructure,[15] the presence of existing high-voltage transmission lines running the entire length of the Project provided an initial routing opportunity that was reviewed and analyzed prior to considering routes that deviated from the existing transmission line corridors. In areas where a potential route following the existing transmission lines encountered significant constraints, possible

[14] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Notice of Intent to Construct, Own, and Maintain the Iron Range – Benton County – Cassie's Crossing Transmission Project (Aug. 1, 2022) (eDocket No. 20228-188015-01); Minn. Stat. § 216B.246, subd. 3.
[15] Minn. Stat. 216E.03, subd. 7(e).

alternatives were developed and considered and compared to identify an alternative that complied with the Minnesota routing requirements and the Project need. Ultimately, MP and GRE identified a Proposed Route that follows or replaces existing high-voltage rights-of-way for more than 85 percent of its length.

3.2 Commission Regulatory Process

August 4, 2023 – The Applicants filed the CON/RP Application.[16]

November 2023 – Following a hearing in October 2023, the Commission issued an order ("Completeness Order")[17] finding the Application complete, authorizing joint hearings and combined environmental review for the CON and RP, and requesting an administrative law judge ("ALJ") from the Office of Administrative Hearings to preside over public hearings and prepare a full report including findings of fact, conclusions of law, and recommendations. In its Completeness Order, the MPUC also ordered the Applicants to identify opportunities to address routing constraints by considering increased use of "infrastructure stacking" above and beyond what is included with the Proposed Route. The Completeness Order is included for reference in Appendix B.

November-December 2023 – The Minnesota Department of Commerce, Energy Environmental Review and Analysis ("EERA"), held public meetings and compiled comments from stakeholders on the scope of the Environmental Assessment ("EA") for the Project. In response to the Completeness Order point on "infrastructure stacking" and to proactively address public and agency comments, the Applicants submitted two "feasible but not preferred" route alternatives for consideration in the EA which both involve co-locating existing lines to address human and environmental constraints in specific areas of the Project.[18] The two co-located alternatives identified by the Applicants are known as the "Riverton Alternative" and the "Cole Lake Way Alternative." After the scoping comment period, the Applicants also responded to route alternatives proposed

[16] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Combined Application (Aug. 4, 2023) (eDocket No. 20238-198009-03).

[17] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, ORDER ACCEPTING APPLICATIONS AS COMPLETE AND ESTABLISHING PROCEDURAL REQUIREMENTS (Nov. 15, 2023) (eDocket No. 202311-200529-02).

[18] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Environmental Assessment Scoping Comments (Nov. 11, 2023) (eDocket No. 202311-200670-04).

by the public and other stakeholders for inclusion in the EA, generally asserting that the Proposed Route and alternatives presented by the Applicants are sufficient for the EA.[19]

February-March 2024 – EERA filed recommendations regarding the scope of the EA and the Commission subsequently issued an order adopting EERA's recommended scope of the EA with modifications ("Scoping Order").[20] The Scoping Order finalized route alternatives to be considered in the EA, adding approximately 35 route and alignment alternatives in total, including the two co-located alternatives submitted by the Applicants and many other route alternatives submitted by the public and other state agencies.

June 2024 – EERA filed the completed EA; the public comment period on the EA and the Project began.

July 2024 – The Applicants submitted direct testimony and exhibits in advance of formal CON and RP hearings to be facilitated by the ALJ. The Direct Testimony of Applicants' witness Christian Winter addressed the Applicants' efforts to evaluate corridor sharing opportunities for the Project and the Applicants' position on the co-location routes being considered in the EA, including concerns about cost, reliability and schedule impacts. Mr. Winter's testimony also provided background on how cost impacts related to the Commission's final route decision may lead to variance analysis under the MISO Tariff.[21] Mr. Winter's testimony is included for reference in Appendix C.

July-August 2024 – The ALJ facilitated public hearings throughout the Project area during the comment period. Formal comments identify a strong preference for co-located options, including the Riverton Alternative and Cole Lake Way Alternative identified by the Applicants and an additional co-location route known as "Alignment Alternative 16 (AA16)" in the Hill City area of the Project. In response to public comments, the Applicants also developed and submitted one additional co-located route alternative to

[19] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Response to Route Alternatives and Conditions Proposed to be Evaluated in the Environmental Assessment – Agencies, Tribes, and Organizations (Dec. 1, 2023) (eDocket No. 202312-200917-01); *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Response to Route Alternatives and Conditions Proposed to be Evaluated in the Environmental Assessment – Comments from Members of the Public (Dec. 8, 2023) (eDocket No. 202312-201101-01).

[20] *n the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Environmental Assessment Scoping Decision (March 22, 2024) (eDocket No. 20243-204589-02).

[21] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Winter Direct (July 8, 2024) (eDocket No. 20247-208392-04).

address constraints in the Elk River area of the Project.[22] With the "Elk River Alternative", there were now four distinct constructable co-located route alternatives that could be selected by the Commission as the final route for the Project.

September 2024 – In response to the public hearing comments, other comments submitted during the EA comment period, and EERA's response to public comments, the Applicants provided two constructable full route options for the Commission's consideration: the MPR and the CLMR. The MPR was largely consistent with the Applicants' original Proposed Route, incorporating certain minor route and alignment alternatives identified during the EA process. The CLMR used the MPR and incorporated all four constructable co-located route and alignment alternatives identified during the EA process. The Applicants presented facts and analysis for the Commission's consideration of the MPR and CLMR, including a comparison of human and environmental impacts, costs, and schedule impacts for each full route option. The updated Project cost estimate ranges for the two full route options compared to the Applicants' original proposed route, as provided to the Commission in the Applicants' response to public hearing comments, are shown in the table below.

Full Route Option	Low ($Millions) (2022$)	Mid ($Millions) (2022$)	High ($Millions) (2022$)
Applicants' Original Proposed Route	$970.0	$1,182.0	$1,353.0
Modified Proposed Route	$980.0	$1,194.2	$1,366.9
Co-Location Maximization Route	$1,122.5	$1,367.9	$1,565.8

The Applicants' full assessment of cost impacts from the MPR and CLMR as provided to the Commission in the response to public hearing comments, are attached as Appendix F. The Applicants did not take a position on a preferred route at this time, instead advising the Commission that either route would satisfy the State of Minnesota routing criteria and would be constructable. The Applicants requested that the MPUC grant a RP for the Project on either the MPR or CLMR based on its own evaluation of the record.[23]

November 2024 – The ALJ filed Findings of Fact, Conclusions of Law, and Recommendations ("ALJ Report") summarizing the record and recommending the

[22] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Comments on the Environmental Assessment and Responses to Requests for Additional Information from the Public Hearings (Aug. 5, 2024) (eDocket No. 20248-209266-01) (*see* Attachment 4 for analysis on the Elk River Alignment Alternative).

[23] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Response to Public Hearing Comments and Comments on the Draft Route Permit at Attachment C at 2 (Sep. 19, 2024) (eDocket No. 20249-210359-05).

Commission grant the Applicants a CON for the Project.[24] The ALJ Report also recommended the Commission grant the Applicants a RP for the Project on the CLMR, with certain modifications recommended by EERA and the ALJ. Subsequently, the Applicants submitted exceptions to the ALJ Report objecting to EERA and the ALJ's recommended modifications to CLMR as infeasible and more expensive and requesting the Commission grant a RP for the Project utilizing either the MPR or the CLMR as proposed by the Applicants.[25]

January-February 2025 – In a hearing on January 23, 2025, the Commission selected the CLMR, with certain modifications, as the final route for the Project. During the hearing, the Applicants informed the Commission that the anticipated mid-range of the cost of the CLMR, as modified for the Commission's decision, was estimated to be $1,369 million (2022 dollars), approximately $187 million more than the estimated mid-range cost of the Applicants' original proposed route. Following the January hearing, the Commission issued an order ("CON/RP Order") on February 28, 2025, granting a CON and RP for the Project on the CLMR with the minor modifications identified by the Commission. The CON/RP Order includes certain other conditions as discussed below.[26]

3.3 Commission Decision

The Commission's CON/RP Order includes decisions related to the CON and route for the Project, as well as various compliance items related to the CON and RP. The following is a summary of order points from the CON/RP Order, focusing on those which are relevant to the purpose of this document. The full CON/RP Order is included for reference in Appendix D.

Order point 1 specifies the Commission's adoption of the ALJ Report, to the extent it is consistent with the remainder of the Commission's decisions.

Order points 2-4, quoted below, pertain to the Commission's decision to grant the Certificate of Need for the Project.

> **Order Point 2:** The Commission grants a certificate of need to Minnesota Power and Great River Energy for the Northland Reliability Project.

[24] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Findings of Fact, Conclusions of Law, and Recommendations (Nov. 8, 2024) (eDocket No. 202411-211770-02).

[25] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Minnesota Power and Great River Energy's Exceptions to the Findings of Fact, Conclusions of Law, and Recommendations of the Administrative Law Judge (Nov. 25, 2024) (eDocket No. 202411-212404-01).

[26] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, ORDER GRANTING CERTIFICATE OF NEED AND ISSUING ROUTE PERMIT, (Feb. 28, 2025) (eDocket No. 20252-215918-01).

> **Order Point 3:** Minnesota Power shall bear the burden of proof in any future regulatory proceeding related to the recovery of any costs above $1,210,000,000. Nothing prevents the Applicant from seeking recovery of additional amounts through the Transmission Cost Recovery Rider.[27]

> **Order Point 4:** Applicants must inform the Commission of the initiation of Midcontinent Independent System Operator (MISO) Variance Analysis under Attachment FF within 5 business days of initiation. Applicants must file all copies of information submitted to the MISO Variance Analysis process. Disclosures must be consistent with Applicants' MISO Tariff.

As seen in these order points, while granting the Certificate of Need, the Commission also established a threshold of cost ($1,210 million) above which Minnesota Power specifically bears the burden of proof in future cost recovery proceedings to demonstrate that the costs above the threshold were reasonably and prudently incurred. It is worth noting that the Commission deliberately established the cost recovery threshold at 25 percent above the original MISO cost estimate for consistency with the variance analysis threshold in the MISO Tariff rather than the cost estimates provided on the record by the Applicants for the route alternatives under consideration. With that intention, the Commission also included an order point requiring the Applicants to inform the Commission if and when MISO initiates variance analysis for the Project, and file copies of all information submitted to MISO during variance analysis, to the extent such disclosures are consistent with the MISO Tariff.

Order points 5-8 pertain to the Commission's decision to grant the RP for the Project on the CLMR, with certain modifications, conditions, and compliance items required in the order points. Order point 9, quoted below, pertains to the impact of the Commission's RP decision on the cost of the Project.

> **Order Point 9:** Within 60 days of the date of this order, Applicants must file revised Project cost estimates in 2022 dollars reflecting the Commission's decision herein.

To ensure the cost of the Project on the CLMR as ordered by the Commission is clearly documented on the record, the Commission required the Applicants to submit a compliance filing within 60 days of the CON/RP Order updating the Project cost estimate to reflect the Commission's decision. The updated mid-range cost estimate for the Project on the CLMR ordered by the Commission is $1,369 million ($-2022). The Applicants preliminarily shared this number with the Commission during the January 23, 2025, hearing prior to the Commission's decision, and subsequently submitted it in a

[27] The project cost referenced in Order Point 3 includes MP and GRE's combined project costs; however, MP as an MPUC rate regulated utility holds the burden of proof for rate recovery. As a not-for-profit cooperative, GRE's costs are allocated to GRE's member-owner distribution cooperatives based on a GRE board approved formula rate methodology.

compliance filing on April 29, 2025.[28] The April 29 compliance filing also informed the Commission that the high-range cost estimate for the Project on the CLMR is $1,567 million ($-2022) and that both the mid-range and high-range cost estimates exceed the $1,210 million threshold relating to cost recovery, as included in the Commission's order point 3. The April 29 compliance filing is included for reference in Appendix E.

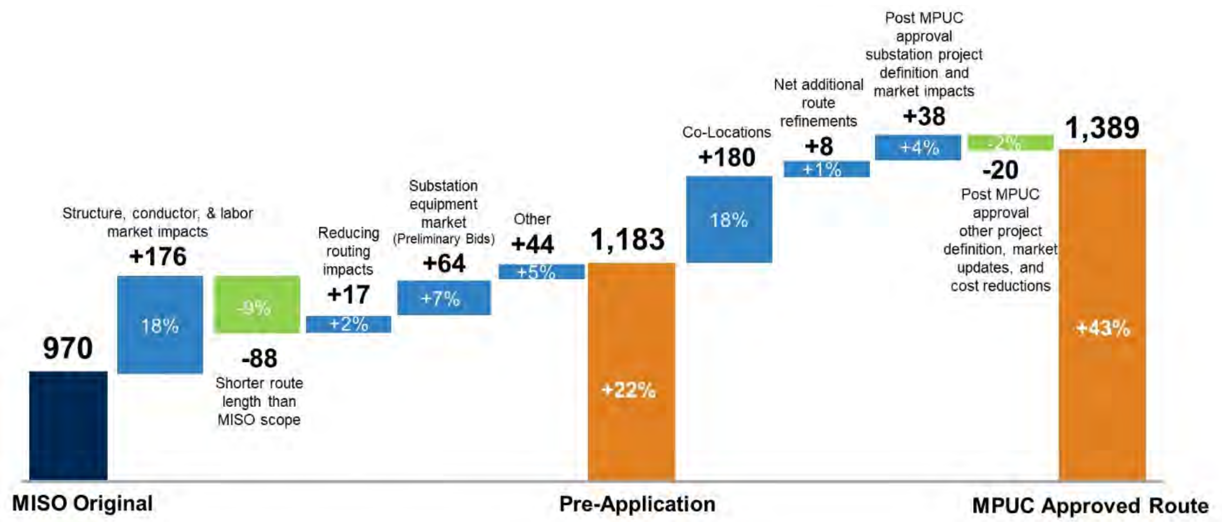
[28] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, 60-Day Cost Compliance Filing (April 29, 2025) (eDocket No. 20254-218276-01).

4 PROJECT SCOPE AND COST UPDATES

This section provides an overview of the underlying scope and cost updates resulting in the current cost estimate for the Project on the MPUC-approved route. Scope and cost updates are broken down into two stages. The first stage ("Pre-Application") consists of scope and cost updates identified by MP and GRE as they undertook Project development, routing, and preliminary engineering activities in preparation for filing the combined CON and RP application. The second stage ("MPUC Approved Route") consists primarily of scope and cost updates resulting from the Commission's final route decision, with additional Project development and engineering updates incorporated as available following the Commission's decision.

As shown in Figure 4-1, the current cost estimate for the Project exceeds MISO's approved cost estimate developed between late 2021 and early 2022 by approximately 43 percent. The increased Project cost is primarily driven by market impacts (25 percent of the 43 percent total cost increase) and routing-related impacts (12 percent), while various scope refinements and other factors also contribute to minor changes in cost (the remaining 6 percent). The Project's MISO approved cost estimate was developed during the early stages and without full knowledge of the impacts of historic inflation, supply chain, tariff uncertainty, and labor market spikes that took place since 2021. Thus, it should be emphasized that under normal market volatility, the net Project cost increase attributable to routing-related impacts, scope refinements, and other factors would be within the 25 percent variance analysis threshold established in the MISO Tariff.[29]

Figure 4-1 – Northland Reliability Project Cost Estimate Change
All values in millions $-2022 - mid-level estimates



In the following sections, the background and justification for each of the major drivers for changes to the Project's costs is discussed in further detail. The discussion of cost impacts is bifurcated into changes that took place as MP and GRE developed the original

[29] MISO FERC Electric Tariff, Attachment FF (Transmission Expansion Planning Protocol) (93.0.0) § IX, *available at* https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/.

proposed route and updated Project scope and cost estimates prior to submitting the CON/RP Application to the Commission (Pre-Application updates), and changes taking place after the Application was filed or resulting from the Commission's CON/RP Order (MPUC Approved Route updates).

4.1 Pre-Application Scope and Cost Updates

Before MISO's approval of the Project in July 2022, MP and GRE had been working for over three years to study and develop the Project to optimally and cost-effectively meet the reliability needs identified by MP, GRE, and MISO. At the same time, MP and GRE understood that identifying a proposed route for the Project would require working with local communities, agencies, stakeholders, and the MPUC to identify a route which reasonably balances human and environmental impacts with engineering, reliability, and cost considerations.

Since MISO's original development of the LRTP Tranche 1 projects and the estimated costs in late 2021 and early 2022, market pressures have continued to have significant impacts on the cost of delivering high voltage transmission projects. Much of this impact is due to global and domestic supply chain pressures originating out of the COVID-19 pandemic, but more recently the global electric utility market and supply chain have been significantly impacted by geopolitical events such as the Russia-Ukraine war starting in second quarter 2022. It should be noted that some of the market impacts are also due to the Tranche 1 portfolio itself, which includes 18 projects and over $10 billion in investment, all requiring similar engineering, materials, and labor resources during a time of high global demand for electric utility infrastructure. Compounding these market impacts, the inflation rate since the original MISO project estimate was developed has been at a historic high.[30] These same inflationary and market pressures will similarly impact all Tranche 1 projects.

As part of the development of the CON/RP Application, the Project team developed an updated cost estimate for the Project. This updated cost estimate, referred to in Figure 4-1 as the Pre-Application cost estimate, was based on GRE and MP's Proposed Route[31] and was developed based on preliminary engineering, scope refinements, and an updated equipment and labor market forecast as of mid-2023. Given the market volatility, MP and GRE acquired multiple bids from contractors and equipment vendors for key transmission line and substation components, used engineering firms to provide updated comprehensive cost estimates for the transmission line and substations, and validated cost estimate assumptions with recent transmission projects across North America.

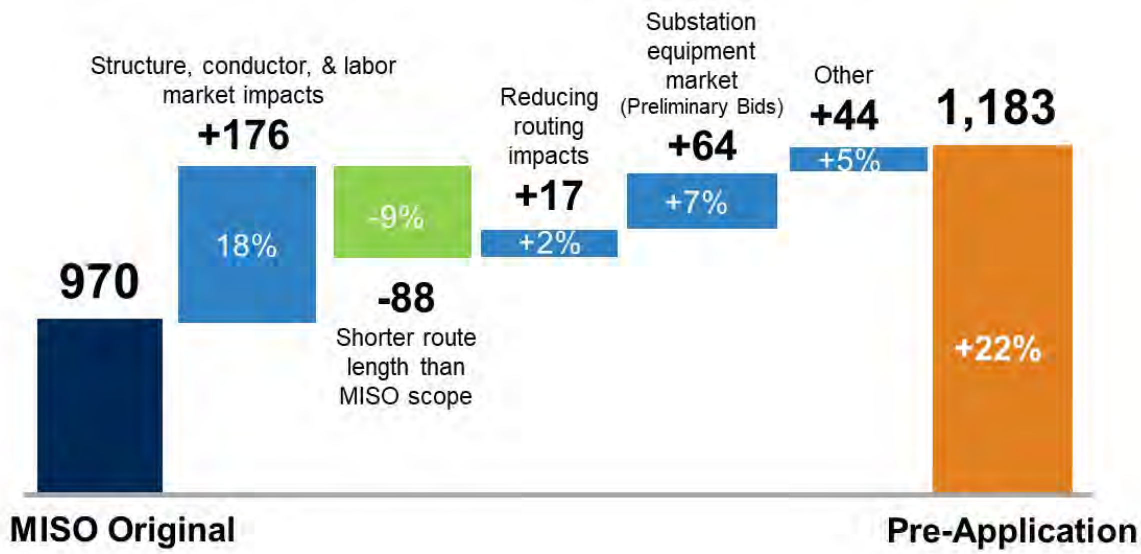
[30] https://www.bls.gov/charts/consumer-price-index/consumer-price-index-by-category-line-chart.htm. U.S. Bureau of Labor Statistics, *12-month percentage change, Consumer Price Index, selected* categories, available at https://www.bls.gov/charts/consumer-price-index/consumer-price-index-by-category-line-chart.htm

[31] *See In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Combined Application at Appendix A (Aug. 4, 2023) (eDocket No. 20238-198009-03). The Proposed Route is detailed in the CON/RP Application in Appendix A.

As shown in Figure 4-2, at the time the Application was filed, the Project was expected to cost approximately $1,183 million ($-2022) – approximately 22 percent higher than MISO's original approved estimate. MP and GRE also included a high-end range of cost in the Application representing various contingencies identified and quantified by the Project team in its risk register. These additional risk contingencies resulted in the high-end range of costs being $1,353 million ($-2022), or approximately 14 percent greater than the expected (or "mid-range") cost.

Figure 4-2 – Northland Reliability Project Cost Estimate Change from MISO Approved Costs to Pre-Application Cost

Figure is a focused view of Figure 4-1
All values in millions $-2022 - mid-level estimates



The increased cost at this stage of the Project was primarily driven by market impacts, with routing and scoping changes contributing minor impacts. While the drivers for the increased Project cost at this stage are discussed in the sections below, it should be emphasized that, even with the unpredicted inflation and supply chain issues, at this stage the total Project mid-range cost was still below the 25 percent variance analysis threshold established in the MISO Tariff.[32] At the time of filing the CON/RP Application in August 2023, MP and GRE considered this updated Pre-Application estimate to be the new baseline cost estimate for the Project. While MISO does not afford projects in right of first refusal ("ROFR") states the opportunity to update the baseline project cost estimate under the Tariff in the way competitive projects' cost estimates are updated, the additional year of preliminary engineering and cost estimate refinement provided important visibility into the full extent of the market and supply chain forces impacting costs for the Project and was important to ensure that the Commission was presented with the most up-to-date cost estimate available at the time of filing the CON/RP Application.

[32] MISO FERC Electric Tariff, Attachment FF (Transmission Expansion Planning Protocol) (93.0.0) § IX, *available at* https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/.

The following sections detail the cost and scope changes from the MISO original cost estimate at the time of MISO Board approval to the Pre-Application cost estimate MP and GRE presented to the Commission in the CON/RP Application filed on August 4, 2023.

4.1.1 Transmission Line Specifications and Market Impacts

Transmission line structure design and conductor selection for the Project was developed based on best engineering practices to comply with the applicable state and federal standards and requirements, meet MISO's electrical performance specifications, and minimize costs and environmental impacts. The Project's transmission structures are tubular steel monopole – consistent with past and current double-circuit 345 kV projects in Minnesota. The Project's general structure design is unchanged from the MISO approved baseline assumptions.

Conductor was selected via an economic and performance-based analysis. The analysis compared the total cost impacts for the life of the Project for conductor alternatives. Only conductors capable of meeting MISO's performance specifications were considered in the economic selection analysis. The conductor selected for the Project not only has the least cost over the life of the Project but is designed to resist icing impacts, such as galloping, which is one of the top threats to reliability in Minnesota. The double-bundled twisted pair 795 ACSR conductor selected as a result of this analysis is slightly larger than conductors previously implemented for 345 kV projects in the region, due to a combination of the MISO-required 3,000 Amp emergency rating and performance impacts relating to the series compensation of the transmission line. As a result, the initial capital cost of the Project's conductor is higher than MISO's original baseline assumptions. However, incrementally higher initial capital costs are offset by lifecycle cost savings from more efficient operation of the transmission line with the larger, lower impedance conductor.

As noted previously, MP and GRE enlisted a consulting engineering firm to develop preliminary design criteria, perform preliminary engineering, update current market assumptions, and produce an updated cost estimate for the Project prior to filing the CON/RP Application. When the CON/RP Application was filed with the Commission in August 2023, the price of steel structures included in GRE and MP's Pre-Application Cost had increased by approximately 36 percent and conductor costs had increased by approximately 19 percent relative to the assumptions in the original MISO approved estimate developed in late 2021 and early 2022. In addition, the labor costs to construct transmission lines had increased. The cumulative impacts of each of these factors along with the preliminary engineering of the transmission line and conductor selection resulted in a cost estimate increase of $176 million ($-2022) or 18 percent from MISO's approved baseline cost estimate as reflected in the Pre-Application cost estimate in Figure 4-2. These same market factors are likely to impact all projects in the LRTP Tranche 1 portfolio.

The Pre-Application cost estimate increases relative to MISO's approved estimate experienced by GRE and MP for the transmission line facilities are also consistent with the Handy-Whitman Index of Public Utility Costs for the North Central Region from July

2021 to July 2023,[33] which show an approximately 20 percent increase in transmission (total transmission plant) costs. Pre-Application transmission line structure, conductor, and construction labor costs were developed from preliminary estimates from equipment vendors, construction contractors, and engineering consultants.

4.1.2 Substation Scope and Market Impacts

Similar to the transmission line facilities, MP and GRE updated the Project substation facilities during development of the Pre-Application cost estimate. Substation facility optimizations and updates were developed based on routing and siting considerations, preliminary engineering, and updated market assumptions. An updated cost estimate was produced for each Project substation facility prior to filing the CON/RP Application. In total, the Pre-Application cost estimates for the three Project substations increased by $64 million ($-2022) which represents an approximately 7 percent increase in the total cost of the Project from MISO's approved baseline cost estimate. The increased substation costs are primarily driven by market factors and inflation.

4.1.2.1 Substation Equipment Market Impacts

Pre-Application substation equipment costs were developed based on preliminary bids from substation equipment vendors and construction contractors. Table 4-1 compares the substation cost assumptions included in MISO's original approved 2022 cost estimate versus the substation cost assumptions used by MP and GRE in development of the Pre-Application cost estimate.

Table 4-1 – Substation Facility Cost Change from MISO Approval to Pre-Application Cost Estimate

Substation	MISO Original Estimate ($M)	Pre-Application Estimate ($M)	Percent Change	Major Drivers
Iron Range 500/345 kV	$70	$92	+31%	Transformers Breakers, Reactors
Riverton (Cuyuna) 345 kV Series Comp	$80	$96	+20%	Location, Series Capacitors
Benton County (Cherry Park) 345 kV	$26	$30	+15%	Breakers Reactors

Due to the increasing global demand, coupled with supply chain and manufacturing shortfalls, the market for transformers, circuit breakers, shunt reactors, and other substation equipment changed substantially between 2021 and 2023. As an example, the cost for the seven single phase 500/345 kV transformers at the Iron Range Substation

[33] The Handy-Whitman Index is a cost index that tracks the price of construction and equipment for electric utilities. It's published by Whitman, Requardt & Associates, LLP semi-annually, on January 1 and July 1.

more than tripled in the five years leading up to the development of the Pre-Application cost estimate in 2023, based on a comparison of the bids received for the Project versus a comparable transformer from 2018. Similar impacts were observed across all categories of major substation equipment.

4.1.2.2 Series Compensation Station Location and Configuration

The original MISO approved Project description specified that the new 345 kV series capacitors required for optimal performance of the Iron Range – Benton County 345 kV lines would be located at the existing MP Riverton 230/115 kV Substation. The Riverton Substation was originally selected because it is an existing substation near the likely electrical midpoint of the new 345 kV lines. After a thorough investigation of available property, site constraints, and route constructability at the Riverton Substation, MP determined that it would not be feasible to locate the series compensation station at the existing Riverton Substation site as originally planned. As a result, MP identified and acquired a tract of county land roughly 3 miles north of the Riverton Substation to facilitate siting of the series compensation in the vicinity of the Riverton Substation as originally planned. Figure 4-3 shows the location of the new Cuyuna Series Compensation Station relative to the existing Riverton Substation and relevant constraints driving the need to find a different site.

Figure 4-3 – Cuyuna Series Compensation Station Siting Considerations

The Cuyuna Series Compensation Station is electrically equivalent to the original Riverton Series Compensation Station specified in MISO's approval. Shifting the location of the series compensation station to a site with adequate space for the new facility enabled development of the original Proposed Route to avoid major human, environmental, and existing infrastructure constraints in the Riverton Substation area. The new location also provided for significantly more flexibility to accommodate future expansion of the Cuyuna Series Compensation Station 345 kV bus to interconnect additional regional transmission lines, support the underlying local transmission system, or facilitate generator interconnections. The series capacitors are sized to offset approximately 52 percent of the impedance of the transmission line segments going north and south from Cuyuna to Iron Range and Benton County/Cherry Park, respectively. Because this is near the practical limit for series compensation of a transmission line, further segmentation of these line segments would require costly replacement and reconfiguration of the series compensation, making Cuyuna the only technically practical point of interconnection on the Project between the Iron Range and Benton County/Cherry Park Substations. To ensure that future interconnections to support the regional grid would be possible at Cuyuna, MP and GRE further clarified the scope of the Cuyuna Series Compensation Station to include a full 345 kV breaker station in between series capacitor segments.

4.1.3 Cost Impact from Development of the Proposed Route

The Proposed Route for the Project was developed over multiple iterations of desktop analysis, survey, community engagement, and agency feedback, as described in Section 3. GRE and MP took great care to ensure the final Proposed Route balanced engineering and constructability considerations, impacts to people and communities, environmental impacts, and costs. While final route selection is the responsibility of the Commission, GRE and MP as Applicants were responsible for developing and filing an initial Proposed Route at the initiation of the state routing regulatory process. During the regulatory process, the public and agencies file alternatives to the Applicants' initial Proposed Route for the Commission's consideration. The Commission ultimately selects the route that best meets the state routing criteria.[34] Section 3 provides a detailed overview of the regulatory process and considerations that went into the Commission's final route determination. This section provides an overview of scope and cost impacts from GRE and MP's initial Proposed Route, which was filed in the CON/RP Application in August 2023.[35] As discussed in Section 3 and later in Section 4.2, modified versions of this route were later developed and considered during the regulatory process.

4.1.3.1 Shorter Route Length than MISO Original Assumption

The Project's initial Proposed Route was approximately 180 miles in total length – 140 miles of new transmission in Segment One (Iron Range – Cuyuna – Benton/Cherry Park) and approximately 40 miles of upgraded transmission in Segment Two (Benton/Cherry Park – Big Oaks & Sherco).[36] The initial Proposed Route followed existing high voltage transmission corridors for approximately 85 percent of its length, meaning the Project's route is either adjacent to existing transmission facilities or replaces existing transmission

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34 Minn. Stat. § 216E.03, subd. 7 and Minn. R. 7850.4100. As noted above, this statute and most parts of this rule were repealed on July 1, 2025 but both were in effect at the time the Commission issued its decision in February 2025.

35 *See In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Combined Application at Appendix §§ 5, 7.2.4 (Aug. 4, 2023) (eDocket No. 20238-198009-03).

36 *See infra* Figure 2-1 for definitions of Segment One and Segment Two.

facilities. Locating the Project adjacent to existing transmission lines helps reduce impacts by being able to share 15 to 20 feet of existing right-of-way and is a required consideration in the Minnesota transmission line routing process.[37] MISO's original approved Project description assumed a Segment One route length of 156 miles. GRE and MP's initial proposed Segment One route was shorter by 16 miles, resulting in a cost savings of $88 million ($-2022) or a nine percent reduction in the total Project costs.

4.1.3.2 Reducing Routing Impacts (Realignments)

The initial Proposed Route followed existing transmission corridors for approximately 85 percent of its length. In Segment One, there are existing 230 kV transmission lines continuously from the Iron Range Substation to the Benton County Substation, providing an opportunity for much of the Proposed Route to be located adjacent to the existing 230 kV transmission lines with overlapping rights-of-way. The side of the existing 230 kV transmission lines on which the Project was proposed to be located was selected to minimize human and environmental impacts and to minimize the number of high voltage transmission line crossings. As the Iron Range Substation is located on the east side of the existing 230 kV transmission line and the Benton County/Cherry Park Substation is located on the west side of the existing transmission line, at least one line crossing was necessary for the Project. During the routing process, it became evident that it would not be feasible to follow one side of the existing 230 kV lines continuously from Iron Range to Benton County without either displacing residential properties or establishing additional line crossings. Even with careful selection of the crossing location to minimize impacts, several pinch points existed along the route corridor which could not be avoided while continuing to parallel the existing transmission lines. To avoid residential displacement, MP and GRE evaluated two options:

1. Cross over the existing 230 kV transmission line (and cross back later); or
2. Realign (shift) the existing 230 kV line and route the Project in the vacated place.

GRE and MP's objectives in this consideration were to develop a Proposed Route that did not require residential displacement, met the reliability needs of the Project by limiting the number of transmission line crossings, and minimized overall cost impacts. Therefore, in the Proposed Route GRE and MP included six realignments of the existing 230 kV lines which, along with other necessary line reroutes at substation sites, added a total incremental cost of $17 million ($-2022). GRE and MP minimized crossings of the 230 kV transmission lines, because high voltage transmission line crossings create increased risks to reliability and resiliency as well as safety during maintenance activities.[38] In

[37] Minn. R. 7850.4100, subd. J.

[38] *See In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Winter Direct at Schedule 3 (July 8, 2024) (eDocket No. 20247-208392-04) ("Line crossings are generally technically possible. However, high-voltage transmission line crossings create unique safety, reliability, and resiliency concerns, while also contributing to increased cost and environmental impacts due to the need for taller and larger structures. Consequently, good utility practice is to minimize new line crossings to the greatest practical extent when routing new high-voltage transmission lines.").

addition, MP and GRE's preliminary engineering evaluation determined that crossing the existing transmission lines would be more expensive than realigning the existing lines for short distances, due to the requirement to install four dead-end structures to turn the line perpendicular to cross over the existing line, then turn the line parallel again to follow the existing line, then turn the line perpendicular again to cross back over the existing line, and finally turn the line again to continue paralleling the existing line on the preferred side.[39] In addition to being taller than other Project structures to provide adequate electrical clearances at the crossing, these dead-end structures would need to be designed with high resiliency to limit the inherent reliability risk associated with the crossing of two regionally-significant transmission lines, resulting in additional costs per structure. Each "there-and-back" line crossing was found to cost approximately $4 million versus the $1.2 to $2.6 million for each realignment avoided.[40] While MP and GRE designed the Proposed Route to minimize the number of realignments, six such realignments were included with the Proposed Route. One of the six realignments in the Proposed Route is shown in Figure 4-4 as an example. Additional descriptions and diagrams of each realignment can be found in Section 2.1.5.4.2 of the CON/RP Application.

Figure 4-4 – Realignment Example

Realignments were added and modified during the regulatory review process and those that were ultimately included with the Commission's final route decision are discussed further in Section 4.2. In addition, as a cost control measure, GRE and MP are required per the Commission's CON/RP Order to attempt to negotiate with the landowners to purchase the properties avoided by the realignments in order to determine whether these

[39] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Response to the MPUC's Request for Comments at 5-7 (January 10, 2025) (eDocket No. 20251-213840-01).

[40] *Id.* at 3-4.

landowners would be willing to relocate, reducing Project costs compared to realigning the line.[41]

4.1.4 Other Pre-Application Optimizations and Refinements

In addition to the market and routing factors, there were a series of other various changes from MISO's approval to the Pre-Application cost estimate. The other scope and cost changes include:

1. Permitting costs,
2. Asset retirement costs, and
3. Segment Two Optionality (detailed in Section 4.1.4.1).

In total, these additional refinements increased the total costs by $44 million ($-2022) or a five percent increase from the original MISO approved baseline cost.

4.1.4.1 Segment Two Optionality

The most significant of these additional optimizations and refinements in terms of Project scope is the addition of double-circuit capable design considerations on the Benton County – Sherco 345 kV line. MISO's original approved description for the transmission facilities in Segment Two between Benton County and Sherco specified construction of a single-circuit 345 kV transmission line with higher capacity than the existing Benton – Sherco 345 kV line. During preliminary engineering and routing analysis, a transmission owner optimization was identified and ultimately included in the CON/RP Application to construct the facilities as single-circuit 345 kV on the double-circuit capable structures built to accommodate a future second 345 kV circuit when conditions warrant. This configuration provides future optionality to double the transmission capacity of the Benton County to Sherco transmission line with no additional right-of-way and with minimal impacts at the time the additional transmission capacity is needed.

Maximizing the use of existing transmission or other rights-of-way is especially prudent in this location given the presence of agricultural center-pivot irrigation, residential development, proposed solar generation, and other local interests. Without this action, it would be extremely difficult and impactful to communities to route a future transmission line through this area. The double-circuit capable structures between the Benton County Substation and the Sherco Substation result in a marginal incremental cost, approximately 20 percent, compared to single-circuit 345 kV structures. However, should the second circuit be needed in the future, it is projected to result in cost savings of at least two-fold relative to a stand-alone option,[42] as shown in **Table 4-2.**

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[41] *See In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, ORDER GRANTING CERTIFICATE OF NEED AND ISSUING ROUTE PERMIT, (Feb. 28, 2025) (eDocket No. 20252-215918-01); Appendix D.

[42] Comparison is conservative as it ignores impacts of inflation and incremental costs associated with future economic development in the area.

Table 4-2 - Cost Comparison of Benton County to Sherco Transmission Line Single- Versus Double-Circuit 345 kV Capability[43]

Single-Circuit 345 kV Cost ($ millions) (2022$)	Single 345 kV – Double-Circuit Capable Cost ($ millions) (2022$)	Cost to add Second Circuit to Double-Circuit Capable Structure ($ millions) (2022$)	Total Cost for Double Circuit Build-out ($ millions) (2022$)	Two Parallel Single-Circuit 345 kV Cost ($ millions) (2022$)
$73.4	$89.5	$9.7	$99.2	$146.8

There is Commission precedent to construct 345 kV facilities to double-circuit capable. Prior to MISO's LRTP, the last regional buildout in Minnesota was CapX2020. The CapX2020 buildout included three 345 kV lines in Minnesota - including the MISO Multi-Value Project ("MVP") between Brookings, South Dakota and the Twin Cities. After comparing multiple options to meet needs including single-circuit 345 kV, 500 kV,[44] and single-circuit built on double-circuit capable 345 kV[45] the Commission ordered the CapX2020 345 kV lines be built as single-circuit on double-circuit capable structures.[46]

Minnesota's double-circuit capable practice has saved costs not only for Minnesota but the broader MISO region. As required by the Commission, the three 345 kV CapX2020 lines in Minnesota were initially strung as single-circuit, but on double-circuit capable structures. In LRTP Tranche 1, the addition of the second circuit position for the southern portion of the CapX2020 line from Alexandria to Monticello was approved by MISO. This project was able to utilize the spare circuit, saving nearly $200 million relative to a new standalone 345 kV circuit.[47] LRTP Tranche 2.1 includes adding a conductor on the remaining spare position of the CapX2020 line between Fargo, North Dakota and Alexandria, as well as adding a conductor on the spare position for the CapX2020 line

[43] *See In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Combined Application at Table 2-2 (Aug. 4, 2023) (eDocket No. 20238-198009-03).

[44] *In the Matter of the Application of Great River Energy, Northen States Power Company (d/b/a Xcel Energy) and Others for Certificates of Need for the CapX 345-kV Transmission Projects,* Docket Nos. ET-2-E-002, *et al*./CN-06-1115, Rakow Direct at 72 (May 23, 2008) (eDocket No. 5228603).

[45] *In the Matter of the Application of Great River Energy, Northen States Power Company (d/b/a Xcel Energy) and Others for Certificates of Need for the CapX 345-kV Transmission Projects,* Docket Nos. ET-2-E-002, *et al*./CN-06-1115, Grivna Rebuttal at 9, 12 (June 16, 2008) (eDocket No. 5278640).

[46] *In the Matter of the Application of Great River Energy, Northen States Power Company (d/b/a Xcel Energy) and Others for Certificates of Need for the CapX 345-kV Transmission Projects,* Docket Nos. ET-2-E-002, *et al*. CN-06-1115, ORDER GRANTING CERTIFICATES OF NEED WITH CONDITIONS at 43 (May 22, 2009) (eDocket No. 20095-37752-01).

[47] Using MISO's MTEP2024 cost estimation guide, the cost would have been approximately $380 million for a new stand-alone Alexandria to Big Oaks 345kV circuit. In comparison the total cost to add the Alexandria to Big Oaks line using the spare circuit (~$130 million) and the initial upfront incremental investment ($35 - $48 million) to make the line double circuit capable was approximately $180 million

between North Rochester and Hampton Corners – thus further providing significant cost savings to the MISO region through the Commission's forward-looking approach. It should be noted the original CapX2020 line from Fargo, and incremental upfront investment to make it double-circuit capable, was a MISO Baseline Reliability Project with costs primarily borne locally by Minnesota ratepayers.

The existing Benton to Sherco 345 kV line has a 69 kV line carried on common structures for approximately 10 miles of the segment. Rebuilding the Benton to Sherco 345 kV line to a higher capacity, as specified by MISO, also requires rebuilding the underbuilt 69 kV facilities. As a result, approximately 10 miles of the 345 kV transmission lines between the Benton County Substation and the Sherco and Big Oaks Substations are designed to also carry a 69 kV circuit on triple-circuit structures. The 69 kV underbuild will be operated at 69 kV but designed and built to 115 kV standards for maintenance and future optionality purposes.

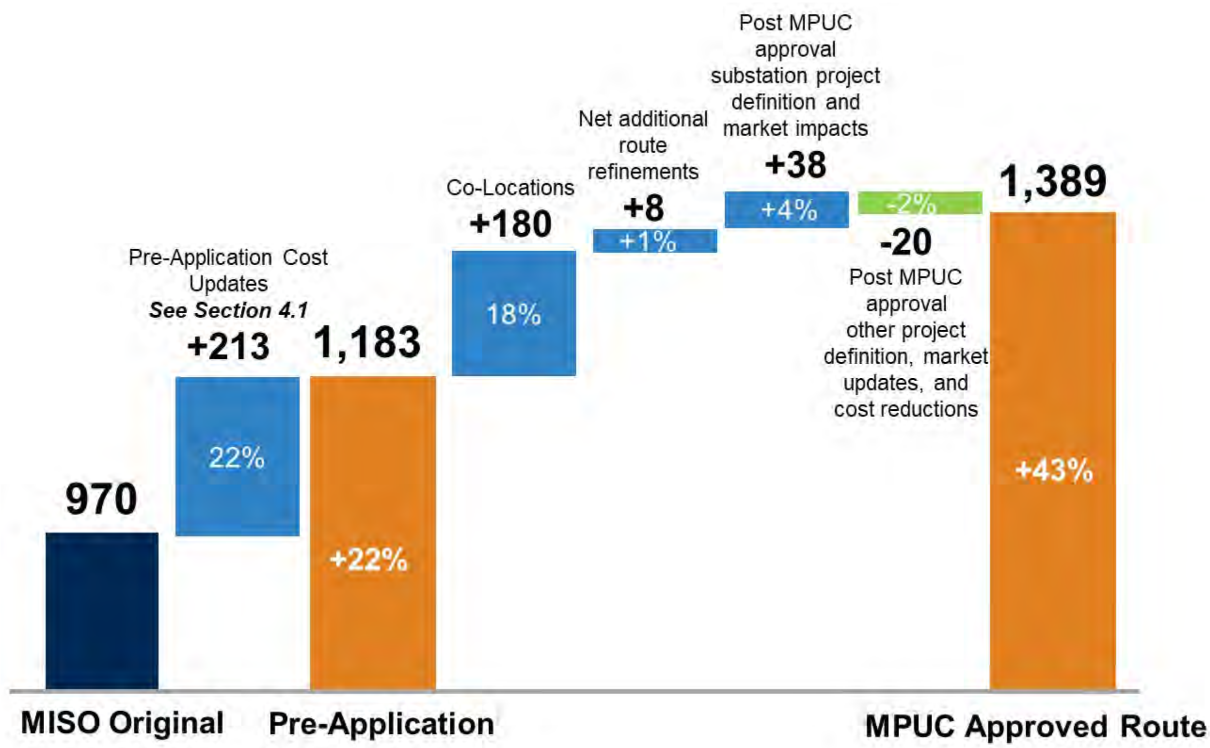
4.2 MPUC Approved Route Scope and Cost Updates

As discussed in Section 3, on February 28, 2025, the Commission issued its CON/RP Order, granting a route permit for the Project on the CLMR as modified by the Commission.[48] Consistent with State of Minnesota routing criteria, the CLMR maximizes utilization of existing high voltage transmission corridors, resulting in the rebuilding of multiple existing high voltage transmission lines on common towers to create right-of-way space for the new double-circuit 345 kV transmission line to be sited. This section provides background and justification for the major scope and cost impacts of the Commission's CON/RP Order, along with additional scope and cost updates developed by MP and GRE since the Pre-Application cost estimate was developed to arrive at the current Project baseline cost estimate. Changes from the Pre-Application cost estimate to the current cost estimate with the MPUC Approved Route are illustrated in Figure 4-5.

Figure 4-5 – Northland Reliability Project Cost Estimate Change from Pre-Application Cost to MPUC Approved Route Cost

Figure is a focused view of Figure 4-1

All values in millions $-2022 - mid-level estimates



[48] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, ORDER GRANTING CERTIFICATE OF NEED AND ISSUING ROUTE PERMIT, (Feb. 28, 2025) (eDocket No. 20252-215918-01).

4.2.1 Co-Location Route Areas

As described in Section 3, the Commission in its Completeness Order required the Applicants to identify opportunities to address routing constraints by considering increased use of "infrastructure stacking" or co-location to further leverage existing utility infrastructure corridors to minimize human and environmental impacts. The Commission and Applicants used the term infrastructure stacking during the Commission proceedings to refer to constructing multiple circuits on a common structure, while the term co-location or common corridor was used to refer to siting multiple circuits adjacent to each other in a common corridor on separate structures. Infrastructure stacking is only feasible if it does not undermine the system reliability needs for the Project.[49]

During the EA scoping comment period, the public, state agencies (e.g., Minnesota Department of Natural Resources), and the Applicants submitted route alternatives for consideration in the EA which involved stacking existing lines. The route alternatives identified by the Applicants were submitted in response to the Commission's direction in its Completeness Order and to proactively address public and agency comments. The two co-location route alternatives identified by the Applicants, which were presented to the Commission as "feasible but not preferred" alternatives, are known as the "Riverton Route Alternative" and the "Cole Lake Way Alignment Alternative."[50] Subsequently in the EA and during the public hearing process, formal comments identified a strong preference from the public and environmental agencies for these two co-location route alternatives and an additional co-location route known as "Alignment Alternative 16 (AA16)" in the Hill City area of the Project. In response to comments received during the public hearings, the Applicants also developed and submitted one additional co-location route alternative to address constraints in the Elk River area of the Project, known as the "Elk River Alignment Alternative." These four major co-location areas, illustrated below in Figure 4-6, constituted the major route alternative options developed and considered in the EA.

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[49] *See In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Winter Direct at 2-3 (July 8, 2024) (eDocket No. 20247-208392-04).

[50] *See Id.* at Direct Schedule 1 at 1; *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Response to Public Hearing Comments and Comments on the Draft Route Permit at Attachment 4 at 2 (Sep. 19, 2024) (eDocket No. 20249-210359-05).

Figure 4-6 – Major Co-Location Areas Identified During the EA Process

Near the conclusion of the route permit process, it became necessary for the Applicants to summarize the record and consolidate the options before the Commission by presenting two constructable full route options for the Commission's consideration. The MPR closely followed the Applicants' original Proposed Route with minor modifications due to route and alignment alternatives, maintaining approximately 85 percent common corridor throughout the Project. None of the four identified co-location route alternatives were included in the MPR. The Applicants estimated the mid-range cost of the MPR to be $1,194 million ($-2022), resulting in an increase of $11 million, less than a one percent increase, over the mid-range cost of the original Proposed Route.[51] The CLMR used the MPR and incorporated the four major co-location areas identified during the EA process. The CLMR route incorporated over 31 miles of rebuilt and double-circuited existing transmission lines and required additional modifications to two substations. The Applicants provided information in the record before the Commission specifying the incremental cost of each co-location alternative and the total CLMR cost estimate.[52] The estimated mid-range cost of the CLMR was $1,368 million ($-2022), or $185 million more than the original Proposed Route, and $174 million more than the MPR.[53]

The Applicants informed the Commission that the CLMR had been developed to meet the Commission's direction in its Completeness Order and that it was the Applicants' position that either the MPR or the CLMR would provide a constructable route for the Project that is consistent with state routing criteria. As stated in the Applicants' exceptions to the ALJ Report, "The Applicants took, very seriously, the Commission's clear direction to fully evaluate how the Project could maximize co-location with existing facilities and developed the Co-location Maximization Route. The record demonstrates that the Co-location Maximization Route meets the state routing criteria and maximizes co-location with existing facilities, as the Commission requested. If the Commission seeks to follow the state routing criteria and prioritize maximizing co-location with existing facilities, the Applicants request that the Commission select the Co-location Maximization Route…. However, if the Commission seeks to follow the state routing criteria and approve a lower cost route without prioritizing maximizing co-location with existing facilities, the Applicants request that the Commission select the Modified Proposed Route…."[54]

Ultimately, the Commission selected the CLMR as the final MPUC Approved Route for the Project, with some modifications. As a result, the four co-location areas, with a total

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[51] *See In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Response to Public Hearing Comments and Comments on the Draft Route Permit at Attachment 2 at 4 (Sep. 19, 2024) (eDocket No. 20249-210359-06).

[52] *See In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Response to Public Hearing Comments and Comments on the Draft Route Permit at Attachment C at 2 (Sep. 19, 2024) (eDocket No. 20249-210359-05).

[53] *Id.*

[54] *See In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Minnesota Power and Great River Energy's Exceptions to the ALJ Report at 1 (Nov. 25, 2024) (eDocket No. 202411-212404-01).

incremental cost impact of nearly $180 million, became system improvements necessary to implement the Project as approved by the Commission, and were incorporated into the scope and cost of the Project.

The relevant background, rationale, and estimated cost impact for each of the four co-location areas is discussed briefly below. The four co-locations approved by the Commission and their corresponding cost as part of the MPUC Approved Route are included in GRE and MP's proposed updates to the MTEP Appendix A Facility List, attached as Appendix A of this document.

4.2.1.1 Riverton Route Alternative

In response to the direction in the Commission's Completeness Order to look for additional opportunities to consolidate the new double-circuit 345 kV transmission line with existing lines, the Applicants submitted the "Riverton Area Alternative Corridor" (also called the Riverton Route Alternative or Route Alternative E1) with their initial EA scoping comments.[55] The Applicants had initially rejected a route alternative following and adjacent to existing transmission lines through the Riverton area due to significant constraints presented by existing infrastructure, lakes, homes, the Mississippi River, and the Cuyuna Country State Recreation Area.[56] However, the Proposed Route through the area received significant opposition from state agencies and the public. After the Completeness Order, the Applicants reviewed the Riverton area again and developed a "feasible but not preferred" route alternative for further evaluation in the EA. The mid-range incremental cost of this co-location area, as it was included in the CLMR and approved by the Commission, was $81.1 million compared to the Proposed Route.[57] The Riverton Route Alternative as originally submitted by the Applicants is shown in Figure 4-7 and described in detail below.

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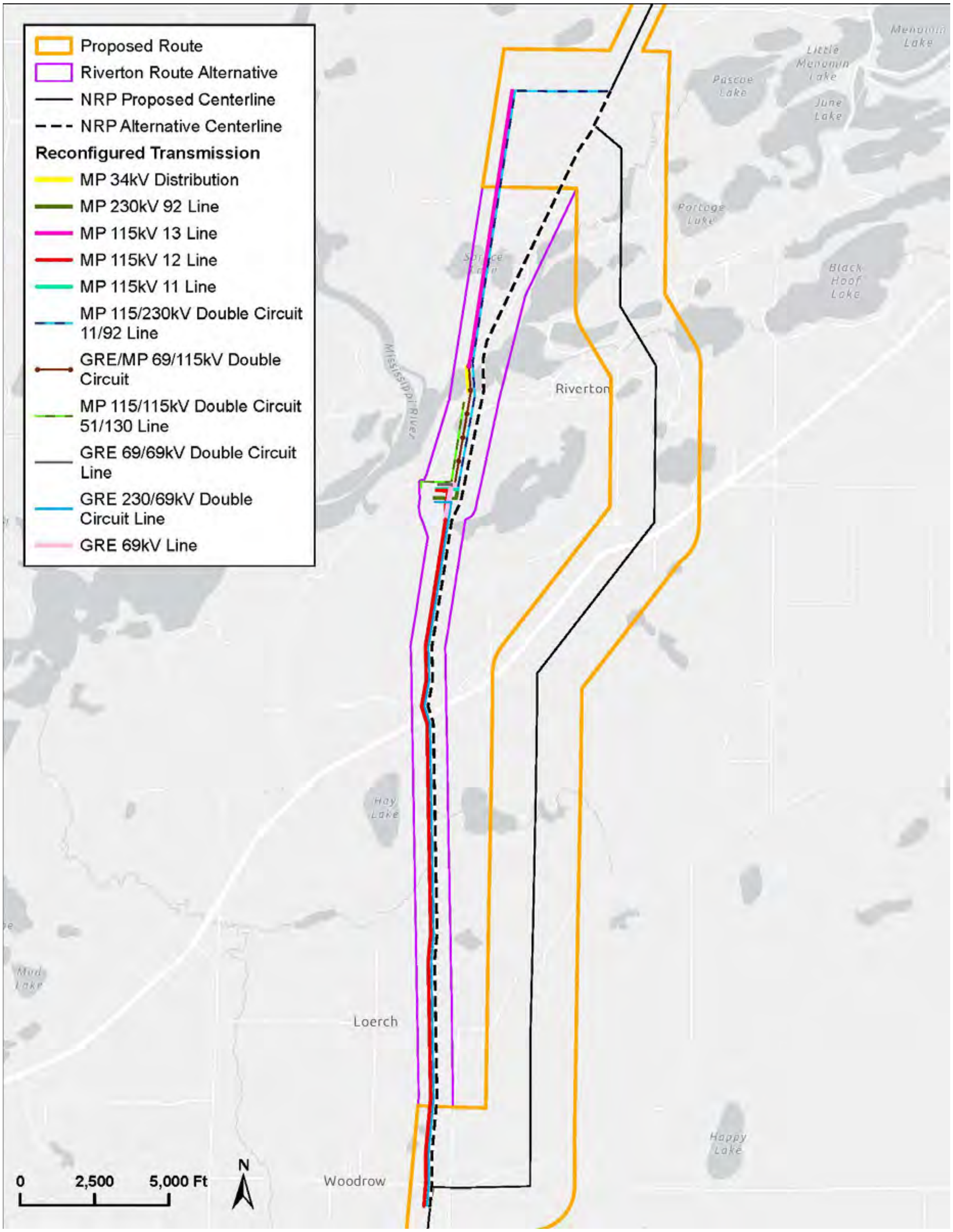
[55] *See In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Environmental Assessment Scoping Comments (Nov. 21, 2023) (eDocket No. 202311-200670-04).

[56] *See In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Combined Application at § 5.3.5 (Aug. 4, 2023) (eDocket No. 20238-198009-03).

[57] *See In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Response to Public Hearing Comments and Comments on the Draft Route Permit at Attachment C at Appendix 4 Table 8 (Sep. 19, 2024) (eDocket No. 20249-210359-06).

Figure 4-7 – Riverton Route Alternative Overview



Starting at the Cuyuna Series Compensation Station, the Riverton Route Alternative replaces MP's existing 230 kV 92 Line with the Project's new double circuit 345 kV line for approximately 1.5 miles until it crosses Little Rabbit Lake.[58] The 92 Line will be relocated and consolidated with an existing 115 kV line in a nearby existing corridor. Following the Little Rabbit Lake crossing, the Project will shift to replacing the existing GRE Riverton – Blind Lake 69 kV Line ("RV" Line) through the Cuyuna Country State Recreation Area for approximately 0.6 miles. The RV Line will be relocated and consolidated with an existing 115 kV line in a nearby corridor. South of MP's existing Riverton 230/115 kV Substation, the Project will replace the GRE Riverton - Wilson Lake 69 kV Line ("RW" Line) as it parallels the east side of the existing GRE 230 kV line and an existing MP 115 kV line for approximately 1.2 miles. The RW Line will be relocated and consolidated with the existing 230 kV line in the same corridor. At the Highway 210 crossing, the entire corridor including the Project, the consolidated 230 kV and 69 kV lines, the 115 kV line, and an existing 34.5 kV distribution feeder, will be relocated to an alignment that balances impacts to homes on both sides of the highway. Approximately 1.4 miles south of Highway 210, the entire corridor will again be shifted to the west to limit impacts to homes along Nelson Road. In this part of the corridor, the Project will take over the centerline of the existing 230 kV line, with the consolidated 230 kV and 69 kV lines and the 115 kV line located to the west in the right-of-way. The Project will continue on this alignment for 1.4 miles until it rejoins the Proposed Route at Woodrow Road. Extensive reconfigurations of existing electrical infrastructure are required to facilitate the Riverton Route Alternative, including those described above as well as additional relocations of existing 230 kV, 115 kV, 69 kV, and 34.5 kV lines. The existing Riverton 230/115 kV Substation will also need to be expanded to accommodate additional 115 kV and 34.5 kV equipment that is necessary to enable the retirement of the existing Riverton 115/34.5 kV Substation, which needs to be removed to facilitate relocation of the existing transmission lines and siting of the Project. In total, the Riverton Route Alternative introduces ten additional 230 kV, 115 kV, and 69 kV segments, four additional 34.5 kV feeders, and two substations to the overall scope of the Project.

4.2.1.1 Cole Lake Way Alignment Alternative

In response to comments from landowners with properties on or near Cole Lake Way and the direction in the Commission's Completeness Order to look for additional opportunities to consolidate the new double-circuit 345 kV transmission line with existing lines, the Applicants submitted the "Cole Lake Way Alignment Alternative" (also called Alignment Alternative AA3) with the initial EA scoping comments as a "feasible" but not preferred"

[58] *See In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Environmental Assessment Scoping Comments (Nov. 21, 2023) (eDocket No. 202311-200670-04); *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Winter Direct at 9-13 (July 8, 2024) (eDocket No. 20247-208392-04).

alternative[59] The Cole Lake Way Alignment Alternative consolidates the existing MP 115 kV 11 Line and 230 kV 92 Line on double-circuit structures, enabling placement of the Project's proposed double-circuit 345 kV transmission line on the right-of-way currently used by the 92 Line in this area. In submitting the Cole Lake Way Alignment Alternative, the Applicants re-iterated their support for the Proposed Route.[60] As the record developed in the CON/RP proceedings, the Applicants provided updates on the anticipated incremental cost of the Cole Lake Way Alignment Alternative.[61] The mid-range incremental cost of this co-location area, as it was included in the CLMR and approved by the Commission, was $29.2 million compared to the Proposed Route.[62]

On December 23, 2024, shortly before the final Commission hearing on the CON/RP Application, the Commission issued a Request for Comments where the Commission asked the Applicants if the Cole Lake Way Alignment Alternative could be extended by nearly 1.5 miles at its northern end to reduce the number of structures crossing the Mississippi River.[63] The Applicants advised the Commission that it was technically feasible to continue the double-circuit of the existing 115 kV and 230 kV transmission lines across the Mississippi River as suggested by the Commission's Request for Comments, and that the additional incremental cost of this added co-location would be approximately $5.9 million.[64] This modification of the Cole Lake Way Alignment

[59] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Environmental Assessment Scoping Comments at 3 (Nov. 21, 2023) (eDocket No. 202311-200670-04).

[60] *See Id.* at 2-3; *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Winter Direct at 12-13 (July 8, 2024) (eDocket No. 20247-208392-04).

[61] *See e.g. In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Winter Direct at 18 (July 8, 2024) (eDocket No. 20247-208392-04); *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Environmental Assessment Scoping Comments Attachment 2 at 2 (Nov. 21, 2023) (eDocket No. 202311-200670-04); *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Response to Public Hearing Comments and Comments on the Draft Route Permit at Attachment C at Appendix 4 (Sep. 19, 2024) (eDocket No. 20249-210359-06).

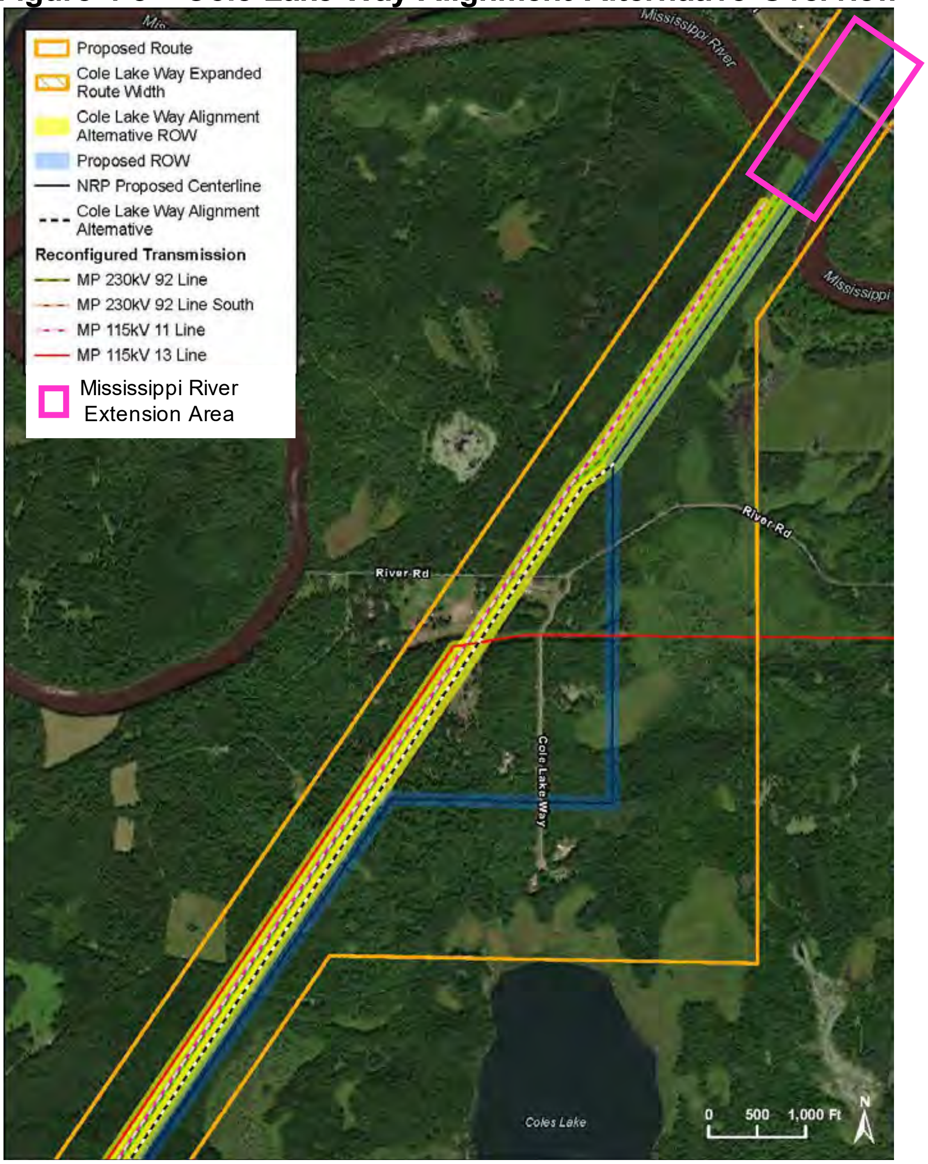
[62] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Response to Public Hearing Comments and Comments on the Draft Route Permit at Attachment C at Appendix 4 Table 7 (Sep. 19, 2024) (eDocket No. 20249-210359-06).

[63] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Notice of Comment Period at 2-3 (Dec. 23, 2024) (eDocket No. 202412-213290-01).

[64] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Response to the MPUC's Request for Comments at 1-2 (January 10, 2025) (eDocket No. 20251-213840-01).

Alternative was subsequently incorporated into the final MPUC Approved Route, bringing the total incremental cost of the Cole Lake Way Alignment Alternative to $35.1 million. The primary constraint area addressed by the Cole Lake Way Alignment Alternative, including the Mississippi River extension area, is shown in Figure 4-8.

Figure 4-8 – Cole Lake Way Alignment Alternative Overview



4.2.1.2 Alignment Alternative 16 ("AA16")

During the EA scoping comment period, an alignment alternative was submitted by a landowner to combine the proposed Project with existing 115 kV and 230 kV transmission lines to mitigate environmental and aesthetic impacts (also called Alignment Alternative

16 (“AA16”)).[65] The Applicants did not object to this alignment alternative being evaluated in the EA, but did note in their scoping comments that no environmental or engineering analysis had been completed at that time. The scope of this alignment alternative involved consolidating the existing MP 115 kV 11 Line and 230 kV 92 Line on double-circuit structures, enabling placement of the Project’s proposed double-circuit 345 kV transmission line on the right-of-way currently used by the 11 Line and the 92 Line in this area.[66] The mid-range incremental cost of this co-location area, as it was included in the CLMR and approved by the Commission, was $41.9 million compared to the Proposed Route.[67] AA16, as evaluated for the EA, is shown in Figure 4-9.

[65] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, EERA Comments and Recommendations on the Scoping Process and Routing Alternatives at 9 (Feb. 13, 2024) (eDocket No. 20242-203365-02).

[66] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Response to Route Alternatives and Conditions Proposed to be Evaluated in the Environmental Assessment – Comments from Members of the Public at 4 (Dec. 8, 2023) (eDocket No. 202312-201101-02).

[67] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Response to Public Hearing Comments and Comments on the Draft Route Permit at Attachment C at Appendix 4 Table 4 (Sep. 19, 2024) (eDocket No. 20249-210359-06).

Figure 4-9 – Alignment Alternative 16 (AA16) Overview

4.2.1.3 Elk River Alignment Alternative

After the draft EA was released, residents at the Sauk Rapids public hearing asked about the possibility of combining existing 230 kV and 69 kV facilities north of Benton County Substation onto common structures to reduce the amount of new right-of-way that would be needed for the Project.[68] In response, GRE reviewed the specific lines in the area and determined that it was possible to combine the existing 230 kV and 69 kV lines in parts of this area where the lines do not serve a common purpose. To maximize co-location opportunities in compliance with the Commission's Completeness Order, the Applicants submitted the "Elk River Alignment Alternative" as a "feasible, but not preferred" alternative.[69] The scope of this alignment alternative involved consolidating the existing GRE 230 kV and 69 kV lines on double-circuit structures, enabling placement of the Project's proposed double-circuit 345 kV transmission line in the right-of-way currently used by the 69 kV line. At the time the Elk River Alignment Alternative was submitted on the record, Applicants provided an estimated range of cost impacts of an additional $22 - $27 million.[70] The mid-range incremental cost of this co-location area, as it was later refined and included in the CLMR and approved by the Commission, was $21.6 million compared to the Proposed Route.[71] The Elk River Alignment Alternative is shown in Figure 4-10 and 4-11.

[68] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Comments on Environmental Assessment and Responses to Requests for Additional Information at Attachment 4 (Aug. 8, 2024) (eDocket No. 20248-209266-02).

[69] *Id.*

[70] *Id.*

[71] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Response to Public Hearing Comments and Comments on the Draft Route Permit at Attachment C at Appendix 4 Table 11 (Sep. 19, 2024) (eDocket No. 20249-210359-06).

Figure 4-10 – Elk River Alignment Alternative North Segment Overview

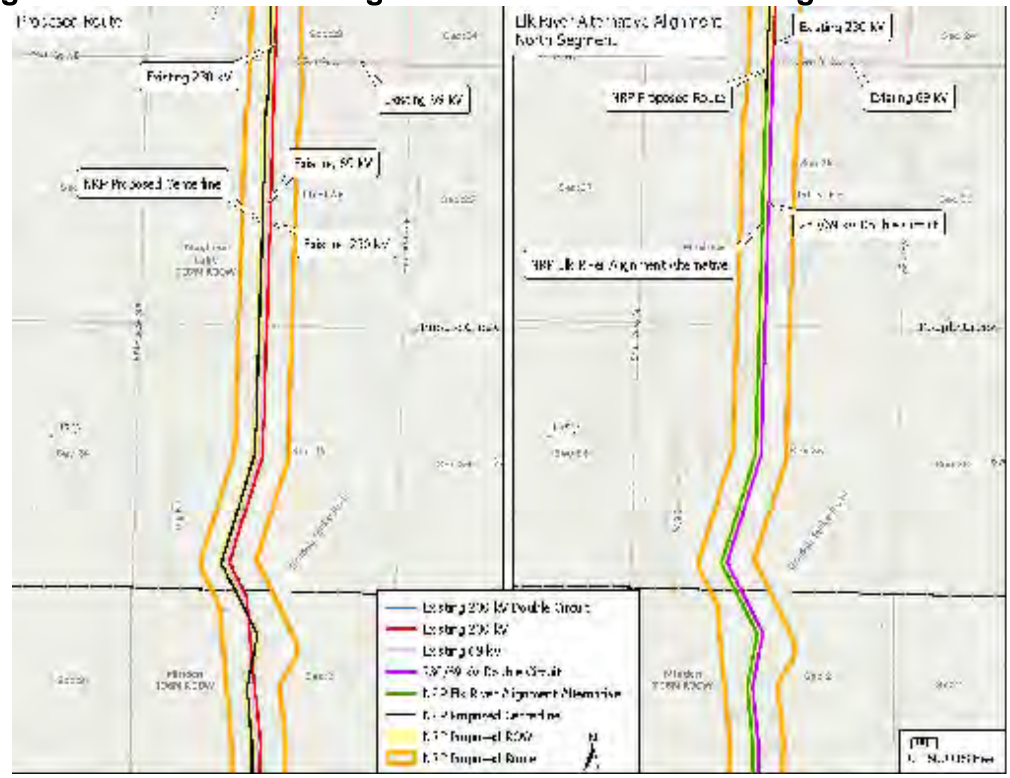
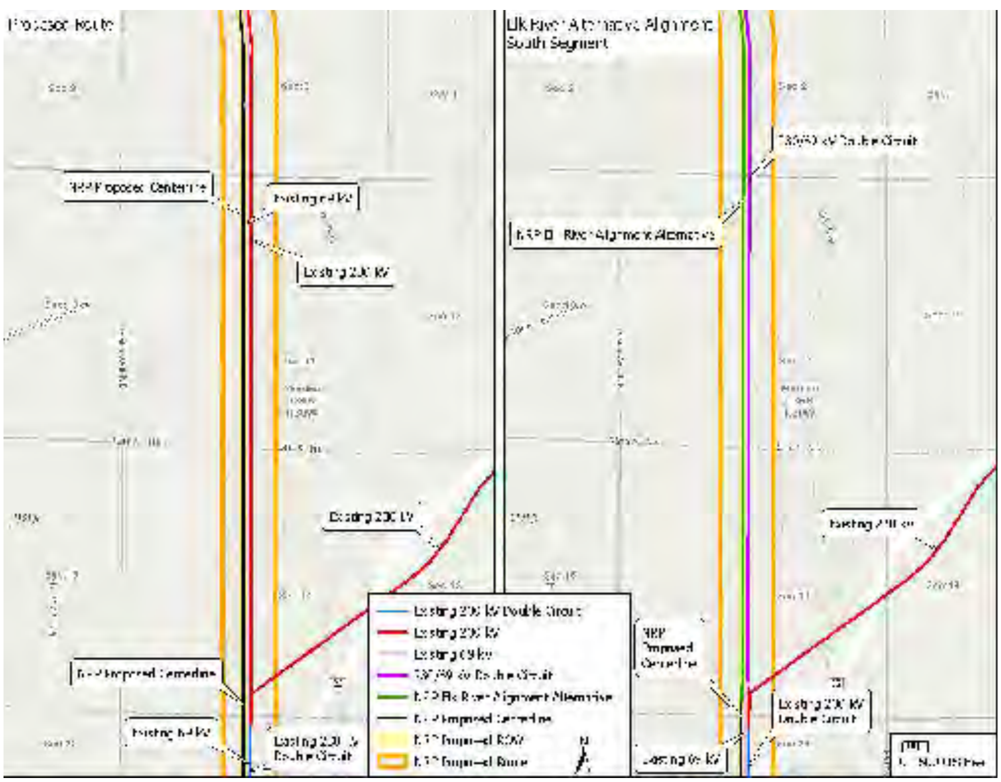


Figure 4-11 – Elk River Alignment Alternative South Segment Overview



4.2.2 Additional Route Refinements

In addition to the four co-location areas described in Section 4.2.1, the final MPUC Approved Route decision includes several additional refinements to the original Proposed Route. Some of these refinements were included with the CLMR as proposed by the Applicants, while others were either added or removed from the CLMR by the Commission. Table 4-3 shows additional minor route refinements that were included in the final MPUC Approved Route. Some of the additional refinements reduced the cost of the Project, while others increased the cost of the Project. In one case, the Commission omitted an alignment alternative proposed by the Applicants as part of the CLMR. The cumulative cost impact of these additional refinements is estimated to be approximately $7.5 million. During the Commission's hearing, there was considerable discussion about the cost impact of the realignments, resulting in the addition of an order point in the Commission's CON/RP Order specifically requiring the Applicants to work with landowners at the affected realignment locations to determine if a lower-cost solution, such as "buy the farm" was available. The Commission's "Order Point on Realignments" is discussed in further detail below.

Table 4-3 – Additional Route Refinements in MPUC Approved Route[72]

Route Refinement	Incremental Cost Impact ($M-2022)	Original Proposed Route	Co-Location Maximization Route	Final MPUC Approved Route
Modified Alignment Alternative AA1	$7.1	Not Included	Included	Not Included
Swatara Route Width Expansion Alignment	$5.3	Not Included	Included	Included
Moose River Alignment	$1.1	Not Included	Included	Included
H4-H7 Alignment	-($2.0)	Not Included	Included	Included
Erickson Alignment	$2.5	Not Included	Not Included	Included
AA17 Realignment	$1.2	Not Included	Included	Included
Sherco Solar Alignment	-($0.6)	Not Included	Included	Included
Total Additional Route Refinements in MPUC Approved Route				**$7.5M**

The CLMR approved by the Commission included an anticipated centerline that incorporates shifting the alignment of existing transmission lines to avoid residences that

[72] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, ORDER GRANTING CERTIFICATE OF NEED AND ISSUING ROUTE PERMIT at 10-11 (Feb. 28, 2025) (eDocket No. 20252-215918-01). A full copy of the Commission's approval order is contained in Appendix D.

have been built near these existing lines. The Commission's Order required that the Applicants continue to work with landowners in advance of finalizing the final alignment for the Project to determine whether there were property purchases that could be completed to eliminate the need to shift the alignment of existing transmission lines ("Order Point on Realignments").[73] The Applicants are required to file a report with the Commission that includes a description of the resolution, proposed actions, and final design for review by Commission staff.

The Commission's Order Point on Realignments, coupled with the Commission's established threshold cost for MP's cost recovery,[74] are cost controls for final Project route realignment costs to be at or below the costs reported in Table 4-3.

4.2.3 Refined Project Scope & Cost Estimate Updates

MP and GRE continued to advance engineering and design of the Project after filing the CON/RP Application and developed an updated Project baseline cost estimate following the Commission's CON/RP Order in February 2025. This section summarizes additional scope and cost estimate refinements that were identified after filing the original CON/RP Application including improved project definition, updated equipment and labor market outlooks, and cost reductions achieved through the Project's contracting and procurement strategy.

4.2.3.1 Substation Project Definition & Market Updates

Site evaluations, detailed design electrical studies, and updated market outlooks from final bids for major Project components impacted the scope and estimated cost of the Iron Range, Cuyuna, and Benton County/Cherry Park Substations. While electrically equivalent to MISO's original approval, the scope of each Project substation has been updated to reflect the final Project configuration and specifications necessary to meet the Project's reliability needs.

The primary changes in each substation are attributed to the size and configuration of reactive compensation. In MISO's original Project definition, 70 MVAR line-connected shunt reactors were included on each 345 kV line at Iron Range and Benton County/Cherry Park to facilitate steady-state voltage regulation within applicable limits. Reactors are especially necessary during energization to limit Ferranti voltage rise along the transmission line and prevent excessive overvoltage at the remote-end substation. As detailed design studies for the Project advanced, it was identified that delayed-zero-crossing ("DZC") concerns would make line-connected shunt reactors infeasible for the Project. The DZC concern is an electromagnetic transient phenomenon that can prevent

[73] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, ORDER GRANTING CERTIFICATE OF NEED AND ISSUING ROUTE PERMIT at Order Point 8, (Feb. 28, 2025) (eDocket No. 20252-215918-01); Appendix D.
[74] Id.

a circuit breaker from operating properly to interrupt a fault, leading to breaker failures and associated reliability issues. Detailed design electrical studies identified that DZC issues would be unavoidable due to the size of the line-end shunt reactors relative to the length of the transmission lines between the breakers located at Iron Range and Cuyuna. However, studies continued to show that shunt reactive compensation would be needed to regulate steady state voltage within design limits at the remote-end substation and along the transmission line during energization.

MP and GRE considered several alternatives for addressing this concern, including implementing smaller reactors, adding reactors at Cuyuna, and changing the connection configuration of the reactors. In the end, the best solution to meet steady state voltage regulation needs without causing DZC issues was to install more (quantity) but smaller (MVAR rating) reactors for the Project, and for all reactors to be bus-connected rather than line-connected. Moving the reactors to be bus-connected allows for voltage control at the sending end of the transmission line during energization to limit overvoltage while keeping the reactors outside the transmission line relaying zone of protection to prevent DZC concerns, mitigating concerns of circuit breaker mis-operations impacting the reliability of the transmission system. In the end, MP and GRE settled on a solution that allows for two 60 MVAR reactors at each Project substation (Iron Range, Cuyuna, and Cherry Park), one on each end-bus, rather than the originally scoped 70 MVAR line reactors at Iron Range and Benton County/Cherry Park. These changes and related design considerations are described for each Project substation below.

Iron Range Substation

The expansion of the Iron Range 500/230 kV substation is required to accommodate the new 500/345 kV transformers and Project 345 kV scope. At the time of MISO approval, the 345 kV substation was designed as a 4-position ring bus, expandable to breaker-and-a-half, with two transformer positions and two 345 kV line positions. Each transmission line also included a line-connected 70 MVAR shunt reactor to regulate voltage during energization and operation of the transmission lines.

As a result of the DZC issues described above, the original 70 MVAR line-connected reactors at the Iron Range Substation were changed to 60 MVAR bus-connected reactors, and two additional 345 kV breakers were added to the Iron Range 345 kV Substation (for a total of six breakers) to complete the breaker-and-a-half configuration with two transformers, two transmission lines, and two bus-connected reactors.

Additionally, detailed design electrical studies identified that three of the planned 500 kV circuit breakers would need to be designed with pre-insertion resistors to mitigate impacts of transformer energization inrush currents, which would cause low voltages on the surrounding transmission system during energization of the Project's planned 1200 MVA 500/345 kV transformers. While similar to standard 500 kV breakers, the addition of pre-insertion resistors to these three breakers impacted both cost and lead time.

Cuyuna Series Compensation Station

The Cuyuna Series Compensation Station ("Cuyuna Substation") is designed with a breakered 345 kV substation in between series capacitor segments to facilitate future substation interconnections without impacting series compensation. The Cuyuna Substation was originally defined in MISO's approval as a 4-position ring bus, expandable to breaker-and-a-half, with each Project transmission line connected to an individual line position. No shunt reactors were included at the Cuyuna Substation.

As a result of the DZC issues described above, two 60 MVAR bus-connected reactors with dedicated reactor breakers were added at the Cuyuna Substation. To facilitate connection of these reactors to the main buses, two additional 345 kV breakers were added to the Cuyuna Substation bus (for a total of six breakers) to complete the breaker-and-a-half configuration of four transmission lines and two bus-connected reactors. These reactors were not originally included in the MISO project definition and became necessary as a result of detailed design electrical studies for the Project.

Benton County/Cherry Park Substation

The expansion of the Benton County 345/230 kV Substation is required to accommodate the new 345 kV lines connecting to Cuyuna and Big Oaks, and the upgraded 345 kV line connecting to the Sherco Substation. At the time of MISO approval, the Benton County 345 kV Substation expansion was designed as a 7-position breaker-and-a-half bus, with two existing 345/230 kV transformer positions and five 345 kV line positions. Each of the two transmission lines to Cuyuna also included a line-connected 70 MVAR shunt reactor to regulate voltage during energization and operation of the transmission lines.

Due to a physical constraint on the property, the most cost-effective option was to extend the existing 345 kV buswork to the west within a new fenced area on the existing Benton County Substation property rather than extending the existing fence line. With the fence physically separated from the Benton County Substation fence, the substation expansion area is named Cherry Park. The substation will continue to have five line positions and two line extensions to the 345/230 kV transformers at Benton County. Cherry Park is electrically equivalent to MISO's approved scope but includes the extension of 350 feet of 345 kV overhead "strain" buswork to connect with the existing Benton County 345/230 kV transformers. Extensions result in four new dead-end structures being needed.

As a result of the DZC issues described above, the two planned 345 kV line-connected shunt reactors, originally 70 MVAR, were moved to bus-connected positions and resized as 60 MVAR reactors. All other Benton County/Cherry Park Substation specifications are equivalent to MISO's original approval.

Summary of Substation-Related Cost Impacts

The updated Project baseline cost estimate following the MPUC Approved Route includes the combined impacts of substation scope changes and market impacts. The net impact of these changes is an increase of approximately $38 million ($-2022). The net change in cost for major substation components from the Pre-Application Project baseline cost estimate to the post-MPUC Approved Route is shown in Table 4-4.

Table 4-4 – Major Substation Component Cost Change from Pre-Application Cost Estimate to Post-MPUC Approved Route Cost Estimate

Component	Percent Change	Major Drivers
Circuit Breakers	+129%	Updated project definition: Six additional 345 kV breakers (2-Iron Range, 4-Cuyuna) Market impacts from final bids
Electrical Equipment Enclosures (EEE)	+97%	Updated project definition at Riverton driven by Commission final route Market impacts from updated bids
Other Materials (Switches, Instrument Transformers, Misc)	+92%	Updated project definition: Additional substation facility scope Market impacts from final bids
Reactors	+22%	Updated project definition: Two additional reactors at Cuyuna
Transformers	+13%	Market impacts from final bids

4.2.3.2 Other Project Definition & Market Updates

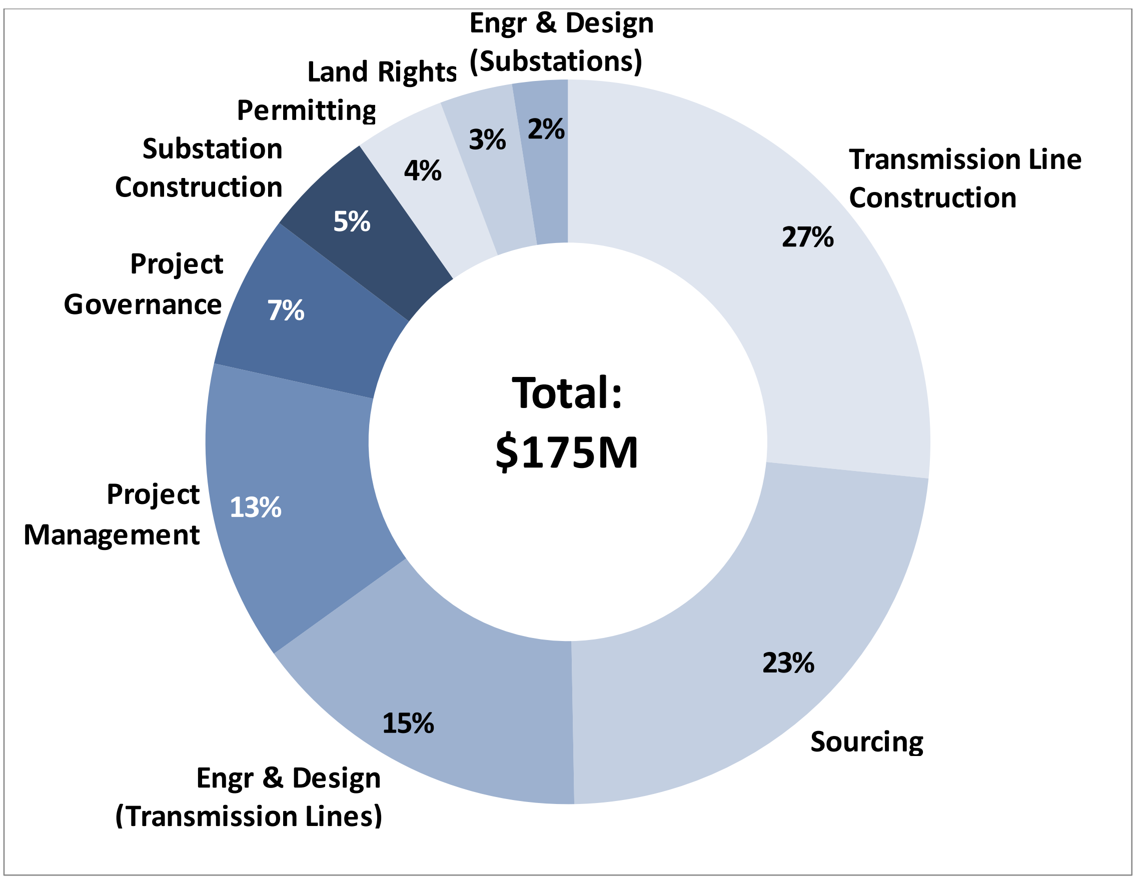
In addition to substations, MP and GRE continued to advance engineering, design, and construction planning efforts for the transmission line facilities. The most significant cost impact is the line length of the Iron Range – Cuyuna – Benton County 345 kV double circuit transmission line in the final MPUC Approved Route that is approximately 16 miles shorter than the original route assumed by MISO. In addition to reduced transmission line costs, GRE and MP were able to proactively reduce construction costs by procuring composite mats to support the Project throughout the duration of construction rather than sourcing them through the line contractor. The total cost **reduction** achieved through transmission line scope refinements, updated transmission line material market outlook, and composite mat procurement is approximately $44 million ($-2022). While these transmission line costs decreased, other general project costs, including project management, engineering, and construction costs, increased by a cumulative amount of approximately $24 million ($-2022) as the scope and construction plan for the Project were refined based on the final MPUC Approved Route, which included significant facility additions to the Project. The combined impact of these cost changes is a **decrease** of approximately $20 million ($-2022).

4.2.4 Project Contingency

The Project cost presented in the preceding sections is the anticipated baseline, or mid-range, cost estimate which does not include contingency. Since the development of the original Pre-Application cost estimate, MP and GRE have also maintained a Project contingency to account for prudent risks and unknowns that exist at each stage of Project development. The Project contingency was developed through an evaluation and development of a risk register. MP and GRE presented the high-end cost estimate of $1.35 billion, including contingency, in the CON/RP Application, alongside the mid-range cost estimate of $1.18 billion and MISO's original approved estimate of $970 million (characterized as the low-end cost estimate).[75]

The current Project baseline cost estimate incorporates changes that have occurred since the development of the original Pre-Application cost estimate, including some changes that were anticipated as risks when the contingency was developed and presented in the CON/RP Application. However, the final MPUC Approved Route incorporates additional facilities and risk factors for construction of the Project, in addition to previously accounted risk factors. In developing the current baseline cost estimate of $1.39 billion, MP and GRE identified and quantified specific Project risks and determined it necessary to carry $175 million of contingency (approximately 13 percent) in addition to the approved Project baseline budget. A breakdown of contingency categories included in the $175 million risk-based Project contingency is given in Figure 4-12.

Figure 4-12 – Breakdown of Risk-Based Project Contingency in Current Estimate



[75] *See In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, Combined Application at 2-13 Table 2-3 (Aug. 4, 2023) (eDocket No. 20238-198009-03).

Major risks accounted for with this contingency amount include transmission line construction contracting cost impacts, the inclusions of several additional transmission line and substation facility modifications resulting from the Commission's final route decision, contract management and change orders for major materials, and tariffs on imported materials in view of the present uncertainty regarding United States tariff policy and its impact on imported materials procured or in the process of being procured for the Project.

4.2.5 Cost controls

MP and GRE have taken proactive cost control measures and remain committed to delivering the Project on time and on the updated budget. Major cost control considerations implemented for the Project include:

- Competitively bidding all major contracts
- Arranging for earlier delivery of some materials where it can reduce costs and/or help mitigate potential tariff impacts
- Partnering with suppliers to secure manufacturing slots for major materials and equipment early and identifying standardized designs where appropriate to reduce costs and lead times
- Early engagement with transmission line construction contractor prior to construction to optimize design and construction efficiencies, including optimizing access planning and tower and foundation designs
- Developing contractor incentives to reduce costs below the current baseline costs, where appropriate (pain share / gain share)
- Scheduling construction work in wetland areas during frozen ground conditions to reduce access and wetland matting costs
- Directly procuring composite mats which may be used multiple times by the construction contractor during construction, saving on the cost of indirectly sourcing matting materials via the construction contractor

MP and GRE are required per the Commission's CON/RP Order to work to identify additional cost savings, including continuing to work with landowners at the proposed realignment locations to determine if property purchases would eliminate the need for the realignments and reduce Project cost.[76] MP is also required per the Commission CON/RP Order to bear the burden of proof to justify to the Commission any Project costs in excess of 1.12 billion ($-2022).[77]

[76] *In the Matter of the Application of Minnesota Power and Great River Energy for a Certificate of Need and Route Permit for the Northland Reliability Project 345 kV Transmission Line*, Docket Nos. E015,ET2/CN-22-416; E015,ET2/TL-22-415, ORDER GRANTING CERTIFICATE OF NEED AND ISSUING ROUTE PERMIT at Order Point 8 (Feb. 28, 2025) (eDocket No. 20252-215918-01). A full copy of the Commission's approval order is contained in Appendix D.

[77] Id. – Order Point 3

5 PROJECT SCHEDULE

The Project's in-service date is June 2030 – unchanged from MISO's approved need date. GRE and MP from the beginning have taken proactive steps to meet MISO's need date, secure contractors and materials, and avoid scarcity pricing. The Project was the first in LRTP Tranche 1 project to file for regulatory permits.

GRE and MP have taken steps in partnership with our construction contractors and suppliers to shift resources to enable the increased project scope from co-locations (Section 4.2.1) and realignments (Section 4.2.2) without delaying the in-service date. With the complex routing constraints and modifications due to the MPUC Approved Route, GRE and MP have taken detailed looks at outage constraints to develop a construction sequence that will limit the impact to the existing system during the buildout of this new double circuit transmission line. GRE and MP are committed to energizing the Northland Reliability Project by June 2030 or earlier.

6 CONCLUSION

Pursuant to Attachment FF of the MISO Tariff, MP and GRE have provided updated costs, facility descriptions, and in-service dates to MISO for MISO LRTP Project #3, the Northland Reliability Project, following the Minnesota Public Utilities Commission's approval of the combined CON/RP Application on February 28, 2025. MP and GRE respectfully request MISO to find that these scope and cost updates are reasonable, prudent, and necessary for the Project, and to incorporate them into the MISO approved scope of LRTP Project #3. Proposed updates to the MTEP Appendix A facilities, descriptions, and costs for the Project are provided in Appendix A of this document.

MP and GRE do not take lightly the fact that the cost of the Project has increased by 43 percent since MISO's original approval. However, MISO's consideration of the prudency of these costs must be informed by the following factors:

1. **LRTP Tranche 1 was approved during a time of significant uncertainty with respect to inflation and market factors.** The original MISO approved cost estimate for the Project was developed during the early stages of portfolio development in late 2021 and without full knowledge of the impacts of historic inflation, supply chain, and labor market spikes that have taken place since 2021. Approximately 25 percent of the 43 percent change in the Project cost estimate is directly attributable to demonstrable changes in the global electric utility market and inflation taking place between the time MISO's original cost estimate was developed in late 2021 and early 2022 and the time MP and GRE updated the cost estimate prior to filing the CON/RP Application in mid-2023. While global economic conditions have stabilized since mid-2023, some of these inflation and market factors continue to impact the Project as updated cost estimates were developed in mid-2025. It must be recognized that under normal historical market volatility, the net Project cost increase attributable to all other factors combined would be well within the 25 percent variance analysis threshold established in the MISO Tariff. These same inflationary and market pressures will similarly impact all LRTP Tranche 1 projects.

2. **Ability to update costs post MISO approval.** Under the MISO Tariff the baseline cost estimate for MVP projects that are either direct assigned upgrades or located in states with a right of first refusal (ROFR) law, like Minnesota, is established at MISO's original Board or Directors approval. In the case of the Project, the baseline project cost estimate was established in July 2022 and developed in late 2021. For other MVP projects that are subject to the competitive transmission request for proposal process, the baseline cost estimate is updated to be consistent with the selected developer's proposal. Depending on MISO's competitive bid schedule for each project, the developer's proposal may be developed and submitted to MISO six to eighteen months after MISO's original Board of Directors approval. The additional time **after** MISO approval allows for preliminary engineering to expand on the original MISO approved project to develop a more accurate and timely cost estimate at the time the baseline cost estimate is set by MISO. Of particular significance for the MISO LRTP Tranche 1 portfolio projects, the additional year provided greater visibility into the extent of the market and supply chain impacts to

costs. The value of this additional development prior to setting the baseline project cost is demonstrated by the fact that over half of the total increase in the cost of the Northland Reliability Project was identified between MISO's original approval in July 2022 and the filing of the CON/RP Application in August 2023. If the baseline cost had been updated at that time to be consistent with MP and GRE's Pre-Application cost estimate, the increased cost resulting from the Commission's route decision and other Project updates since August 2023 would not exceed the 25 percent cost threshold for variance analysis.

3. **Routing, constructability, and engineering.** At the time of MISO approval multiple key factors are unknown, including routing and detailed engineering. It is the responsibility of transmission owners, GRE and MP, to engineer and route a constructable project which aligns with MISO's original justification for the project, meets MISO's performance requirements and other applicable specification and design requirements, and complies with state regulatory policies. Scope changes for this project (e.g. reactors, substation sites, etc.) were necessary to meet MISO's specified reliability need and respond to technical and practical challenges identified during development of the Project. The final route including co-locations selected and approved by the Commission is reasonable and prudent given the priorities and routing criteria in the State of Minnesota. There is only one Commission-approved route for the Project, which was selected by the Commission after a long and rigorous regulatory review process, including consideration and balancing of human, environmental, engineering, and cost impacts. The Project cannot be constructed without incorporating the co-locations included in the Commission's final approved route. With respect to the prudency of the co-locations, it should be emphasized that the Project is just one in a series of regional transmission projects which either have or will come before the Commission. As such, the Commission's interest in utilizing options like co-location to minimize routing impacts is essential to the successful implementation of the multi-phase LRTP and aligns with MISO's interest in seeing the LRTP projects constructed and placed into service. Finally, none of these scope or cost changes degrade the Project's capability to deliver the benefits identified in the MISO LRTP analysis.

In addition to incorporating scope and cost updates into Appendix A as proposed, MP and GRE request that MISO recognize that some contingency remains prudent and necessary. GRE and MP respectfully request MISO to reestablish the project baseline cost at $1,389 million ($-2022) and set a new variance analysis threshold at 13% ($1,564 million) - consistent with the Project's contingency established via the risk register (see Section 4.2.5). As a mitigation plan, GRE and MP are willing and ready to provide MISO regular updates to track project costs, scope, and schedule. In addition, GRE and MP are willing to provide MISO materials provided to the Commission to justify any project expenditures over $1,210 million (MISO original approved cost + 25%). Finally, GRE and MP will continue to look for opportunities to further reduce costs from the baseline and mitigate additional costs impacts from potential tariffs or additional supply chain pressures, as directed by the Commission and in accordance with good utility practice.

APPENDIX A: Proposed MISO Appendix A Updates

Facility ID	Name	Facility Description	Facility Owner	Current Cost	Expected ISD	Facility Type	From Sub	To Sub	kV	Miles New	Miles Upgrade	Updates from MISO Approval
27053	27053-Benton County/Cherry Park-Big Oaks	Replace existing GRE single circuit 230 kV with double circuit 345 kV transmission line. Uncross existing Benton to Big Oaks (Monticello) and Benton to Sherco lines. A portion of new line will underbuild an existing 69kV line.	GRE	$139,871,000	6/1/2030	Line Rebuild	Cherry Park (Benton County)	Big Oaks	345	0	25	Updated Name, Description, Owner, Cost, Type, Endpoints, and Miles. Incorporated Facility ID 27051 for simplicity of reporting
27054	27054-Benton County/Cherry Park-Sherco	Replace the existing Benton County-Sherco single circuit 345 kV to accommodate a rating greater than 3000 Amps on double-circuit 345 kV capable structures. Including north dead-end structure for new conductor. Uncross existing Benton to Big Oaks (Monticello) and Benton to Sherco lines. A portion of new line will underbuild an existing 69 kV line.	GRE	$106,013,000	6/1/2028	Line Upgrade	Cherry Park (Benton County)	Sherco	345		21.4	Updated Name, Description, Owner, Cost, Endpoints, and Miles. Incorporated Facility ID 27052 for simplicity of reporting
27055	27055-Benton County/Cherry Park	Add 345 kV 7-position breaker-and-a-half bus with 2 transformer positions and 5 line positions (one an existing modification), with two bus connected 60 MVAR shunt reactors on Cherry Park bus, and modify 23 0kV position for one 230/345 kV transformer going to Benton County Cherry Park is at the Benton County Substation site but a separate fenced area due to physical site constraints.	GRE	$45,152,000	6/1/2030	Substation	Cherry Park (Benton County)		345			Updated Description, Owner, Cost, and Substation Name.
27056	27056-Benton County/Cherry Park-Cuyuna	Construct new 345 kV double circuit transmission line, including the following relocations and realignments to enable siting of the new facility in or adjacent to existing rights-of-way per State of MN routing criteria: 3.5 miles of MR 230 kV Line relocation and retermination at Benton County, 5.1 miles rebuild of MR/BP 230/69 kV on double circuit structures, 4.5 miles rebuild of MR/RW 230/69 kV on double circuit structures, 4.3 miles rebuild of 115 kV 12 Line, 6.3 miles rebuild of 115 kV 13 Line, and 7 targeted realignments of MR 230 kV Line.	GRE, MP	$415,744,000	6/1/2030	Line New	Cherry Park (Benton County)	Cuyuna	345	68	23	Updated Name, Description, Cost, Endpoints, and Miles. Includes underlying system improvements ordered by the MPUC route decision
27057	27057-Cuyuna	Construct new 6-position 345 kV breaker-and-a-half bus near the existing Riverton 230/115 kV Substation. Add 4-345kV series capacitor banks (1 for each line segment going north and south) with protective bypass equipment. Impedance of series capacitor bank will be approximately 52% compensation. Cuyuna is approximately 2 miles from the existing Riverton 230/115 kV Substation site due to physical site constraints and land availability.	MP	$116,436,000	6/1/2030	Voltage Device	Cuyuna		345			Updated Name, Description, Owner, Cost, and Substation Name.
27058	27058-Cuyuna-Iron Range 500/230kV	Construct new 345 kV double circuit transmission line, including the following relocations and realignments to enable siting of the new facility in or adjacent to existing rights-of-way per State of MN routing criteria: 19.2 miles of 115 kV 11 Line and 20.3 miles of 115 kV 92 Line	MP, GRE	$407,612,000	6/1/2030	Line New	Cuyuna	Iron Range 500/230 kV	345	66	40	Updated Name, Description, Cost, Endpoint, and Miles. Includes underlying system improvements ordered by the MPUC route
27059	27059-Iron Range 500/230kV-	Expand existing Iron Range 500 kV Substation to establish a 5-position 500 kV ring bus (line to Dorsey, 500-230 TX, 500-345 TX, Cap Bank, 500-345 TX), add 2-345/500 kV 1200 MVA transformers (with 1 single phase spare on-site), and add 4-position 345 kV breaker-and-a-half bus for 2-345/500 kV transformer positions and 2-345 kV line positions (includes 2-345 kV bus connected shunt reactors, est. 60 MVAR each). Includes rerouting of existing 230 kV and 115 kV lines around substation expansion area.	MP	$115,879,000	6/1/2030	Substation	Iron Range 500/230 kV		345			Updated Description, Owner, Cost, and Type. Incorporated Facility ID 27060 and Facility 27061 for reporting
TBD	TBD-Riverton Substation Relocation	Relocation of existing Riverton 115/34 kV Substation and equipment into Riverton 230/115 kV Substation, upgrades to Riverton 230/115 kV Substation, and retermination of existing transmission lines at Riverton 230/115 kV Substation to enable siting of the new double-circuit 345 kV line in or adjacent to existing rights-of-way per State of MN routing criteria.	MP, GRE	$43,188,000	6/1/2030	Substation	Riverton 230/115 kV		230, 115		2.1	New Facility added to describe additional underlying system improvements ordered by the MPUC route decision