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May 9, 2025

VIA E-FILING

Mr. William Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
Saint Paul, MN 55101-2147

Re: **In the Matter of the 2025 Biennial Transmission Projects Report**
Docket No. E999/M-25-99

Dear Mr. Seuffert:

Minnesota Transmission Owners (MTO) respectfully submit these reply comments.

These reply comments have been e-filed through www.edocket.state.mn.us. A copy of this filing is also being served upon the persons on the Official Service List of record.

Please let me know if you have any questions regarding this filing

Sincerely,

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DRM:ML

STATE OF MINNESOTA
BEFORE THE
PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Hwikwon Ham	Commissioner
Audrey Partridge	Commissioner
Joseph Sullivan	Commissioner
John Tuma	Commissioner

In the Matter of the 2025 Biennial Transmission Projects Report	**Docket Number: E999/M-25-99** **REPLY COMMENTS**

INTRODUCTION

Minnesota Transmission Owners (MTO) respectfully submit these Reply Comments in response to the Minnesota Public Utilities Commission's (Commission) February 14, 2025 Notice (Notice) seeking comments on the appropriate methodology for calculating the payback period of grid enhancing technologies (GETs). Initial comments were filed on April 11, 2025 by the Department of Commerce, Division of Energy Resources (Department), EDF Renewables (EDF), and the Working for Advanced Transmission Technologies (WATT) Coalition. In these Reply Comments, the MTO provides a response to each commenter, and respectfully requests that the Commission adopt the recommendations outlined in the MTO's Initial Comments.

DISCUSSION

I. REPLY TO DEPARTMENT

In its comments, the Department recommends:

(a) technology specific benefit-cost ratios;

(b) GETs projects should be studied for all current and projected areas of congestion, so long as the project can generate benefits for a minimum of two operational years; and

(c) the MTO's analysis of GETs include:

(i) interactions of multiple GETs,

(ii) interactions of a single GET with a substation or transformer upgrade; and

(iii) substation or transformer upgrades in isolation.

The Department also provided comments on the other issues in the Notice. The MTO welcomes the Department's analysis and recognition that GETs can provide additional benefits beyond relieving congestion.[1] In its initial comments, the Department noted that "[a]t this time, it is not clear to the Department how to calculate a technically valid payback." The MTO offered two approaches to calculate a payback for GETs: (1) a shadow price dollar per megawatt ($/MW) and (2) a Congestion Charge.[2] The MTO continues to prefer the Congestion Charge approach and welcomes feedback from the Department and other parties.

As the Department noted, the Minnesota session law requires the MTO calculate a payback period for each GET based on a methodology adopted by the Commission. In lieu of a specific methodology, the Department recommends applying a benefit-cost ratio (BCR) in evaluating GETs. The MTO's comments focused on how the payback period will differ by the technology, i.e. shorter for dynamic line rating (DLR) implementation versus longer and near the expected life for capital-intensive projects such as new batteries. The Department's BCR approach applies a similar logic, with a lower BCR for DLR implementation and a higher BCR for GETs that require more capital and ongoing operations and maintenance expenses, such as topology optimization projects. However, the Department did not address what the BCR should be for capital-intensive projects.

The MTO continues to believe its approach to calculate specific payback periods based on specific types of GETs, is reasonable, practical, and appropriate. MTO believes the Department's

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[1] Department Initial Comments at 2-3.

[2] MTO Initial Comments at 5-6.

BCR approach can provide helpful insights into whether a specific GETs project should be considered for implementation. However, while BCR is a useful tool for comparing the benefits and costs of a project, it is a limited measure and should be used in conjunction with other analyses and considerations. The Department recommends the Commission set specific BCR values for specific technologies. For example, a BCR of 1.25 for power flow controllers and topology optimization, due to their potential to shift congestion to other areas of the grid, and 0.75 for DLR and dynamic transformer ratings (DTR) projects. A BCR greater than 1 suggests a potentially worthwhile project, but it does not consider all factors that influence project success. While BCR can be helpful to assess the relative cost-benefit balance of proceeding with a specific project, the MTO opposes setting specific, hard BCR values as the sole determinant of whether a transmission owner should pursue a specific GETs project. A well-informed decision-making process should incorporate concepts such as BCR along with other analyses like Net Present Value (NPV) and Internal Rate of Return (IRR), as well as considering factors like risk, strategic alignment, and stakeholder perspectives.

In response to the Notice requesting comments on addressing future congestion, the "Department recommends that GETs projects should be studied for all current and projected areas of congestion, so long as the project can generate benefits for a minimum of two operational years."[3] The Department also expressed concerns for implementing GETs when an expected transmission upgrade will alleviate the need for the GETs. While the Department's perspective on this issue is informative, the MTO maintains that requiring this evaluation for potential future congestion runs the risk of increased ratepayer costs with little to no benefit.[4]

[3] Department Initial Comments at 7.

[4] See MTO Initial Comments at 7.

Regarding equity issues, the MTO agrees with the Department's discussion that relies upon existing Minnesota statutes to provide a framework for developing a GETs payback period methodology. The MTO will continue to work with the Commission, the Department and other stakeholders in evaluating equity, workforce and environmental justice factors.

Finally, the Department expressed concerns "that GETs solutions studied in isolation may not produce a sufficient number of viable projects."[5] The Department based this in part on Xcel Energy's comments in Docket No. E999/CI-24-316 and the limited availability of GETs as solutions for transmission constraints in southwest Minnesota. Therefore, the Department recommended the MTO include in the upcoming 2025 Biennial Transmission Projects Report (2025 BTPR) additional analysis that addresses "interactions of multiple GETs, a GET coupled with a substation or transformer upgrade, or a substation or transformer upgrade made in isolation."[6] The GETs analysis for the 2025 BTPR is already underway; the MTO will assess whether it is able to incorporate the Department's recommendation of a combination of GETs and traditional substation upgrades subject to any study limitations. However, the MTO notes that adding interactions of GETs will complicate the analysis and create study challenges and there is limited time to finalize and submit the 2025 BTPR by November 1, 2025.

II. REPLY TO EDF

The MTO values EDF's thoughtful comments in response to the Notice and agrees with EDF's advocacy for further deployment of cost-effective GETs. EDF's experience in Midcontinent Independent System Operator (MISO) and elsewhere provides helpful context for

[5] Department Initial Comments at 10.

[6] Department Initial Comments at 10.

evaluating payback periods and alleviating congestion. The MTO highlights EDF's comments on characterizing benefits of GETs solutions:

> It is also important to note that benefits of a GETs solution could be regional/systemwide but also very localized. A GETs solution could have a fast pay-off even if its positive impact is local. The Commission should encourage GETs solutions for both local and regional congested pockets, as long as they remain cost-effective.[7]

The MTO agrees that GETs can provide both local and regional benefits and recognizes there are important considerations impacting various stakeholders.

III. REPLY TO WATT COALITION

The MTO values the WATT Coalition's comments in response to the Notice and its recognition that Minnesota is a leader in grid modernization. The MTO concurs with the WATT Coalition that GETs can "have additional benefits beyond addressing congestion"[8] and welcomes further discussions on how to maximize these benefits for all Minnesota customers.

The WATT Coalition highlights four facilities in Minnesota that were included in the MISO Reliability Subcommittee's Top 10 Congestion Cost Constraints.[9] The MTO agrees GETs may be part of the solution to relieve congestion, but notes that solutions for these four constraints are very complex. The four highlighted facilities are presently being analyzed in the GETs study being undertaken by the MTO and as such they are being considered for GETs solutions. Additional analysis would need to be conducted to ensure that congestion is not simply shifted to another part of the system. Until the analysis is completed it would be premature to comment further on these congestion points.

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[7] EDF Initial Comments at 3.

[8] WATT Coalition Initial Comments at 4.

[9] WATT Coalition Initial Comments at 5.

Additionally, the WATT Coalition's recommendation to conduct production cost modeling "with and without GETs in service, over 8670 hours in all relevant years to determine the total likely cost savings"[10] is problematic. As the MTO noted in its initial comments,[11] PROMOD modeling tools have challenges in replicating all the historical constraints. The MTO continues to assert that its proposed recommendation of a Congestion Charge is a better methodology to meet the Minnesota legislative directive compared to the WATT Coalition's production cost modeling approach.

The MTO's approach and recommendation is supported by MISO's planning process. As MISO noted in its 2023 MISO Transmission Expansion Plan (MTEP23) Report:[12]

> The MISO economic planning process is geared towards long-term planning horizons rather than near-term planning horizons. In addition to adjustments that are needed in model development to better reflect the near-term, topology changes can shift or eliminate congestion making it challenging to use historical data to identify near-term issues and solutions.

Additionally in the October 11, 2023 MISO Planning Advisory Committee presentation entitled "Update on MTEP23 Near-Term Congestion Study"[13] the key takeaways included:

> • Informational study reviewed historical, Day Ahead (DA) congestion data and attempted to recreate congestion in MISO economic models to provide insight into potential economic benefits, measured by a change in Adjusted Production Cost (APC).
>
> • MISO's economic model and processes are developed to inform long term planning horizons and not near-term horizons. MISO will continue to explore how to adapt economic models and processes to identify near-term issues and solutions.

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[10] WATT Coalition Initial Comments at 6.

[11] MTO Initial Comments at 5.

[12] Attached as Appendix A to these Reply Comments. MISO MTEP23 Report (Chapter 3, Page 11) available at: https://cdn.misoenergy.org/MTEP23%20Chapter%203%20-%20Regional%20and%20Interregional%20Planning%20Studies631233.pdf

[13] Attached as Appendix B to these Reply Comments.

The presentation further described that "[h]istoric day ahead congestion cost does not perfectly translate to MISO APC savings in economic models" due to generation and transmission outages in real time, transmission system upgrades, and generator additions and retirements.

Finally, similar to EDF, the MTO recognizes there are important considerations impacting various stakeholders and shares the WATT Coalition's concerns that meaningful stakeholder engagement is essential for the deployment of GETs throughout Minnesota.

CONCLUSION

The MTO appreciates the comments of other parties and will continue to engage on issues related to GETs as we prepare the 2025 BTPR.

Dated: May 9, 2025

Respectfully submitted,

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APPENDIX A

2023 MISO TRANSMISSION EXPANSION PLAN (MTEP2023) – CHAPTER 3

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CHAPTER 3: REGIONAL AND INTERREGIONAL PLANNING STUDIES

3.1 Long Range Transmission Planning

The Reliability Imperative focuses on preparing the region for industry transformation as the grid evolves toward increased decarbonization goals and renewable resources. As a critical part of this effort, Transmission Evolution assesses the region's future transmission needs and associated cost allocation holistically, including transmission to support member plans and state goals for existing and future generation resources. Long Range Transmission Planning (LRTP) is part of this effort.

The LRTP initiative is MISO's response to the current and future resource evolution that has and continues to affect the bulk electric system. The scale and pace of these changes require prompt attention to develop the most efficient, cost-effective investments that will ensure grid reliability in the future. LRTP sets out to proactively identify key regional backbone transmission projects to support the resource change. This requires MISO to balance regional issues which should be addressed now as part of the LRTP study versus those more localized issues which should be addressed in the future through the interconnection process or in future MTEP cycles as specific load and generation locations are determined. Ultimately, the objective of the LRTP study is to identify a least-regrets transmission build-out evaluated against multiple scenarios to manage uncertainty that achieves member goals, maintains reliability, and minimizes costs.

LRTP Tranche 1 Update

On July 25, 2022, MISO approved Tranche 1 of its LRTP study, which included 18 transmission projects with a total estimated cost of $10.3B (2022$). In the first year after project approval, Transmission Owners have continued to work on more detailed engineering design and construction plans and some Transmission Owners are starting to make regulatory filings with the applicable government agencies. As project updates have been available, Transmission Owners have provided those to MISO for its project reporting, which are shared on MISO's public website.

Additionally, as applicable, MISO has solicited proposals and selected developers for transmission projects in Tranche 1 eligible for the Competitive Transmission Process. Five Request for Proposals for Competitive Transmission Projects resulted from Tranche 1, all which MISO issued within one year of Board approval. In May 2023, MISO selected Republic Transmission to develop a competitive transmission project located in Indiana. In October 2023, MISO will select a developer for a competitive transmission project located in Missouri, and in February and April 2024, MISO will select a developer for each of the remaining three competitive transmission projects. MISO looks forward to future collaboration with Transmission Owners as the transmission projects in Tranche 1 are further designed, constructed, and placed in service.

LRTP Tranche 2 Status

Currently, MISO has moved to the next phase of the LRTP work, referred to as Tranche 2. This next Tranche will continue the work of Tranche 1 focusing on the Midwest Subregion of the MISO footprint. An important distinction from Tranche 1 is that Tranche 2 will utilize Future 2A of the recently developed Series 1A Futures to ensure transmission is available in a timely manner and meets member objectives.

In the time between the start of the Series 1 Futures (2019) and the end of the LRTP Tranche 1 effort (2022), significant changes occurred, namely acceleration of membership decarbonization and renewable plans and State policies. This acceleration drove the need to refresh the Futures and hence the Series 1A was developed.

Tranche 2 kicked off in quarter three of 2022 with the refresh of the MISO Futures. Along the way, many LRTP Workshops have been held as well as discussions at the MISO Planning Advisory Committee (PAC) to engage stakeholders in the LRTP process. Furthering stakeholder communication efforts, MISO also developed a set of Frequently Asked Questions (FAQ) to provide a broad base of information on various LRTP topics. The first key deliverable in the LRTP Tranche 2 study was completion of the updated Future 2A expansion and siting, which is the foundation for the current work on the economic and reliability models. Additional near-term key focus areas include:

- Reliability dispatch methodology and scenarios, see Reliability Modeling Whitepaper for more detail
- Issues identification using economic and reliability models
- Portfolio development to resolve regional issues
- Continued definition and refinement of robustness scenarios to ensure identification of least-regrets solutions
- Identification of benefit metrics for Tranche 2 to demonstrate multiple distinct types of value from the portfolio

Stakeholder engagement will continue throughout the process as transmission system models are completed, analysis is performed and issues identified, necessary grid enhancement solutions are developed, scenarios are analyzed, and benefits of a proposed portfolio are quantified. Tranche 2 efforts are expected to be completed with BOD approval in 2024.

LRTP Tranche 3 Status

MISO's Long Range Transmission Planning (LRTP) effort has multiple workstreams to support the different Tranches going on in parallel. Namely, MISO's current focus is on execution of the competitive process for Tranche 1, modeling and analysis for Tranche 2, and cost allocation discussions for Tranche 3.

In the most recent FERC filing to support the bi-furcated sub-regional MVP cost allocation for Tranches 1 & 2, MISO committed to exploring an alternative cost allocation approach for Tranche 3 focused on MISO South. To effectively pursue adjustments to the methodology, MISO and its stakeholders are actively engaged in evaluating options. These conversations are centered around three main criteria:

- Granularity – alignment on definition and scope of granularity and how it is considered in benefit calculation and allocation methodology
- Feasibility - evaluation tools and techniques available to determine beneficiaries
- Consistency – recognition that benefits and beneficiaries may change over time and applying a cost allocation methodology that remains just and reasonable over time

Ongoing conversations can be monitored in the Regional Expansion and Criteria Working Group (RECBWG). Additionally, we appreciate the ongoing effort of OMS' Cost Allocation Principles Committee (CapCom), Entergy Regional State Committee Working Group (ERSCWG) and other stakeholder groups in the development of a cost allocation approach for use with Tranche 3 focused on MISO South.

3.2 Interregional Studies

MISO-SPP Joint Targeted Interconnection Queue (JTIQ) Study

Introduction and Background

The JTIQ Study is a result of MISO and SPP's cluster study observations which show that transmission systems at the seams are at capacity. While the addition of generation resources and transmission along the SPP-MISO seam provides benefits to the markets, current Tariff and Joint Operating Agreement (JOA) mechanisms do not provide a cost-sharing approach that can facilitate the construction of the large-scale transmission needed to interconnect expected levels of new generation near the seam. Process, criteria, and schedule differences between the respective RTOs contribute to study delays and introduce questions on study results. The JTIQ Study takes these various barriers into consideration.

JTIQ aims to provide cost and timing certainty for generator interconnection customers as affected system costs will be known at the beginning of the MISO or SPP queue studies in addition to the elimination of Affected System Studies (AFS) needed between MISO and SPP. Moreover, this concept will identify more optimized network upgrades as compared to individual AFS clusters in the current process. The full report is available here .

Study Results

Through collaboration between the MISO and SPP Regional Transmission Organizations (RTOs), the study identified a five-transmission-project JTIQ portfolio with a planning level estimated cost of $1.06B required to address the significant transmission limitations restricting the opportunity to interconnect new generating resources near the MISO-SPP seam.

The recommended JTIQ Portfolio is expected to fully address the set of transmission constraints evaluated in the JTIQ Study as being significant barriers to the development of new generation along the MISO-SPP seam. In addition to these substantial reliability benefits, economic analysis conducted by the RTOs show customers can anticipate an Adjusted Production Cost (APC) benefit over a 10-year period of $55.7 million in the MISO footprint and $132.9 million in the SPP region. An estimated 28.7 GW of improved interregional generation enablement would be available to new generator interconnection projects near the seam.

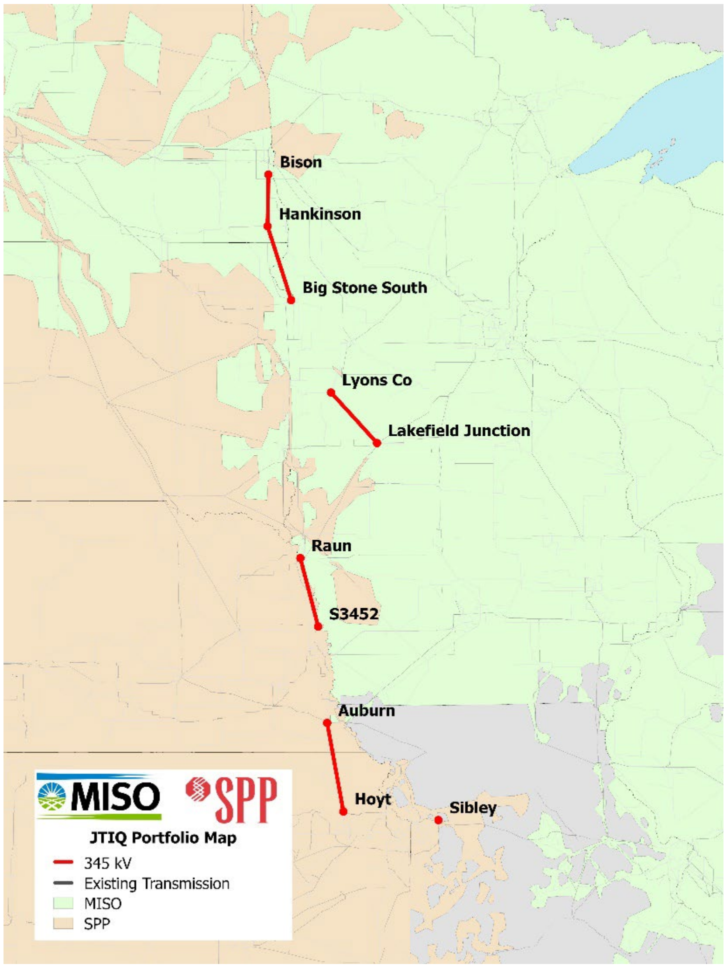


Figure 3.2.1-1: JTIQ Portfolio Map

JTIQ Portfolio	Location by RTO	Cost ($M)
Bison – Hankinson – Big Stone South 345 kV	MISO	476
Brookings Co (*moved to Lyons Co.) – Lakefield 345 kV	MISO	331
Raun – S3452 345 kV	MISO - SPP	144.4
Auburn – Hoyt 345 kV	SPP	90.5
Sibley - 345 kV Bus Reconfiguration	SPP	18.8
Total Cost of Portfolio of Projects	**MISO - SPP**	**1,060.7**

Table 3.2.1-1: List of projects comprising the JTIQ Portfolio

JTIQ Portfolio Update

The original portfolio included the Brookings Co-Lakefield 345 kV JTIQ project which will be replaced by a shorter Lyons Co-Lakefield 345 kV project in the updated JTIQ portfolio due to an approved MISO MTEP 22 project, Brookings Co-Lyons Co 345 kV second circuit on existing structures. MISO and SPP are working on updating the 2023 cost estimates and APC benefit calculations based on the updated model. RTOs will share this information once the data is available.

Cost Allocation and Cost Sharing

Projects in the JTIQ Portfolio are Generator Interconnection Projects, at the 345 kV voltage level, and, accordingly, the costs will be allocated consistent with the existing cost allocation method for Generator Interconnection Projects 345 kV and above. Each generator interconnection customer included in the group and allocated costs of the JTIQ Portfolio will pay their share of capital costs based on the size of their facility in proportion to the total enabled MWs of the portfolio. Non-capital costs associated with the generator interconnection customer's share will be allocated consistent with each RTO's current regional Tariff. MISO and SPP will allocate the share attributable to load based on application of the Adjusted Production Cost metric and each RTO will recover those costs consistent with its regional Tariff.

Department of Energy (DOE) – Grid Resilience and Innovative Partnership Program (GRIP)

In collaboration with SPP, Minnesota Department of Commerce, Minnesota Commission, Transmission Owners and Great Plains Institute, MISO supported the application for partial funding of the JTIQ projects through the DOE Grid Innovation Program. Below is a timeline of this year's activities.

JTIQ Concept Paper Submission	January 2023
DOE Notification to Submit Full Application	March 2023
Application Submitted	May 2023
DOE Notification of Award	Pending

Pending the DOE decision, the GRIP award could match up to 50% of the JTIQ portfolio. MISO and SPP do not anticipate this decision to impact current processes and will work with the DOE and interested parties to integrate any funding as appropriate.

Joint Operating Agreement (JOA) and Tariff updates

The MISO-SPP JOA captures changes in the planning processes, Affected System Study process, and allocation of costs between the two RTOs. MISO and SPP are collaborating with the stakeholders on updating the JOA redlines.

Summary of MISO Tariff Changes:

- Attachment X and related Appendices will be modified and potential new agreements added to incorporate the JTIQ Portfolio consistent with the MISO-SPP JOA changes
- Module A and Attachment FF are clarified and augmented to capture that the existing Generator Interconnection Project category and cost allocation applies to the JTIQ Portfolio of Generator Interconnection Projects
- New Attachments and Schedules will detail how costs will be charged to generator interconnection customers and MISO load, and how costs will be recovered and paid between the two RTOs

3.2.2 MISO-SPP Coordinated System Planning

In Q1 of 2023, MISO and SPP held an Annual Issues Review with the Interregional Planning Stakeholder Advisory Committee (IPSAC) to help determine whether to perform a Coordinated System Plan (CSP) study in 2023. After careful consideration and stakeholder discussion, MISO and SPP mutually determined not to initiate a CSP study based on the following rationale:

- No significant interregional congestion drivers were identified for consideration

- Forgoing 2023 CSP will better allow for the coordination of filing Targeted Market Efficiency Projects (TMEPs) in the MISO-SPP Joint Operating Agreement following the 2022 CSP, which involved developing the TMEP process and completing the first TMEP study with stakeholders
- No appropriate reliability constraints or public policy drivers were identified or planned at this time

3.2.3 MISO-PJM Coordinated System Planning

In Q1 of 2023, MISO and PJM held an Annual Issues Review with the Interregional Planning Stakeholder Advisory Committee (IPSAC) to help determine whether to perform a Coordinated System Plan (CSP) study in 2023. After careful consideration and stakeholder discussion, MISO and PJM mutually determined not to initiate a CSP study based on the following rationale:

- No interregional congestion drivers were identified for consideration as a part of an Interregional Market Efficiency Project study
- A Targeted Market Efficiency Project study was conducted in 2022, MISO and PJM recommended waiting another year before considering completing another study in order to have a full two years of new historical data to utilize
- No appropriate reliability constraints or public policy drivers were identified or planned at this time

3.3 Near-Term Congestion Study Update

Introduction and Background

MISO production cost analysis has traditionally focused on the medium- to long-term planning horizons with past Market Congestion Planning and Long-Range Transmission Planning initiatives. While MISO continues to prepare for the rapidly changing energy landscape of the future, some MISO stakeholders expressed interest in additional analysis focused on the near-term time horizon.

After reviewing the proposed issue in the MISO Interconnection Process Working Group and MISO Market Subcommittee, the issue was eventually assigned to the MISO Planning Advisory Committee (PAC) under PAC-2021-1: Address Congestion at Existing Resources and delegated to the Planning Subcommittee (PSC) for further stakeholder technical discussion. Additional information on stakeholder discussions and presentations on this issue can be found on the MISO website at *PAC-2021-1 Address Congestion At Existing Resources*.

Stakeholders proposed a similar process to the existing MISO-PJM Targeted Market Efficiency Project (TMEP) study process. TMEPs are quick-hit, low-cost interregional projects to address specific interregional market-to-market congestion issues. Notably for TMEPs, the evaluation process is limited to only a review of historical day-ahead (DA) market data rather than production cost modeling or simulation. To accommodate a more robust analysis of the MISO region (versus the limited Market-to-Market historical-only data review), MISO staff proposed a hybrid approach that would use traditional production cost modeling and simulation to evaluate issues, with a focus on the issues driving historical top congested flowgates.

MISO recreated the top identified flowgates in an available model. To better understand key drivers, additional assumption and model tweaks will be tested prior to determining final study recommendations.

Study Objectives and Scope

The primary objective of this study was to provide insight into recent top congestion issues seen in the MISO Day-Ahead market and identify the challenges of near-term economic modeling. MISO does not plan to recommend projects for approval based on the results of this informational study. Voluntary pursuit of any project proposals by stakeholders based on the study results should be performed in accordance with the planning processes and timelines outlined in the MISO Transmission Planning Business Practice Manual (BPM-020) and the MISO-PJM Joint Operating Agreement (MISO-PJM JOA Article IX). Cost allocation outside of market participant funding for any specific upgrades are not in scope for this effort.

Flowgates studied were determined using the following process:

- Screening Criteria:
  - Historical Day-Ahead market data from 2021 and 2022
  - Congestion cost, binding hours, and shadow prices
  - Data included Market to Market (M2M) flowgates, but was limited to MISO-only facilities
- Flowgates were organized by their binding element and ranked by total congestion cost
- Facilities were removed from consideration using the following criteria:
  - Project went in-service during study window which had a noticeable positive effect on congestion cost
  - Project is planned to be in-service in the near-term at the facility
  - Facility was examined extensively as part of other MISO studies (JTIQ, LRTP, TMEP, etc.) and solutions were identified

Model was developed under the following assumptions:

- We used the following Hitachi PROMOD[1] releases
  - Fall 2021 gen updates and economic data
  - Spring 2022 coal prices
  - PROMOD 11.5 engine
- MTEP23 No Futures Assumptions model
  - Hartburg – Sabine was removed
  - Out of cycle projects were added if in-service date was before study window
- MTEP22 Year 2027 Summer Peak TA powerflow
- Resource utilization – generators with signed GIA additions and finalized retirement studies were included.

Study

Initial Analysis

Ten flowgates were identified for this study based on their historical congestion from 2021-2022 (see Table 3.3-1). Project testing was conducted by running the base case model, then evaluating whether historical day-ahead congestion was duplicated under the Year 5 assumptions. Only one flowgate, the Marblehead North 161/138 kV transformer, was identified as being congested in the base case model.

[1] PROMOD, Hitachi Energy owned, is a chronological security constrained unit commitment and economic dispatch tool that adheres to a wide variety of operating constraints.

Monitored Facility	State	Owner	Total MISO DA Congestion Cost ($)	Base Economic Model Congestion Cost* (Year 2027)
Marblehead North 161/138 kV Transformer	IL	Ameren	103,084,055	$283,232
Johnson Junction – Graceville 115 kV	MN	GRE	71,148,820	
Cayuga 345/230 kV Transformer	IN	Duke	39,638,357	
Irvine – Beacon 161 kV	IA	Alliant West	39,602,576	
Jefferson County – Woody 161 kV	IA	Alliant West	30,763,191	
Cayuga – Hillsdale North 230 kV	IN	Duke	29,928,665	
Murphy Creek – Hayward 161 kV	MN	SMMPA/ALTW	28,681,570	
Stone Lake 345/161 kV Transformer	WI	Xcel	28,385,411	
Fox Lake – Rutland 161 kV	MN	SMMPA/ALTW	23,485,327	
Woody – Appanoose	IA	Alliant West	23,098,944	

Table 3.3-1: Top 10 List of Most Congested MISO Flowgates in 2021-2022
*Annual average shadow prices x number of binding hours

Outage Analysis

Congestion at each binding facility was further reviewed to identify outage driven congestion. MISO noted congestion that may be driven by outages due to a significant number of nearby outages during similar periods of congestion. Transmission Owners of the monitored facilities in the study provided additional insight into the impacts of outages or general cause of congestion (see Table 3.3-2).

Monitored Facility	MISO Identified Outage Impacts	Additional Information from Facility Owner
Marblehead North 161/138 kV Transformer	X	
Johnson Junction – Graceville 115 kV	X	The Johnson Junction to Graceville congestion issue was directly related to the planned construction outage on the Johnson Junction to Morris line which occurred between Oct 1,2021 and Feb 1, 2022. The normally open line segment north of Graceville was closed in to accommodate this construction outage leading to congestion on the Johnson Junction to Graceville line. Thus, the congestion correlates the construction of the Johnson Junction-Morris construction outage and grid reconfigurations. It is understood that when upgrading transmission facilities to accommodate the changing grid, it is often necessary to alter the normal operations of the transmission system which can lead to temporary

Monitored Facility	MISO Identified Outage Impacts	Additional Information from Facility Owner
		economic congestion in order to ensure continued grid reliability. (GRE)
Cayuga 345/230 kV Transformer	X	Congestion was likely related to Cayuga Unit 1 outage and MTEP Project 22226 is expected to relieve this congestion. (Duke)
Irvine – Beacon 161 kV		Congestion was highly correlated to several outages including MEC Diamond Trail-Hills 345 kV, MEC Montezuma-Ottumwa 345 kV, and ITC Beacon-Tri County 161 kV line upgrade outages. Ottumwa Generation outages may have also increased congestion on the line. (ITC)
Jefferson County – Woody 161 kV		Congestion was likely related to MEC Diamond Trail-Hills 345 kV line and Ottumwa Generation outages. (ITC)
Cayuga – Hillsdale North 230 kV	X	Congestion was likely related to Cayuga Unit 1 outage and MTEP Project 22226 is expected to relieve this congestion. (Duke)
Murphy Creek – Hayward 161 kV	X	Congestion was likely related to XCL Crandall-Wilmarth 345 kV line upgrade outage and ITC Adams 161 kV bus outage to connect a new generator. (ITC)
Stone Lake 345/161 kV Transformer		Facility owner confirmed minimal outage impacts. Congestion may have some relation to Manitoba Hydro flows. Congestion in 2023 has not been as extensive likely due to the refurbishment of the Eau-Claire - Arpin 345 kV line. MTEP Project 20229 is expected to further reduce binding on this line. (Xcel)
Fox Lake – Rutland 161 kV	X	Congestion was likely related to XCL Crandall-Wilmarth 345 kV and ITC-Lakefield-Dickinson County 161 kV line upgrade outages. (ITC)
Woody – Appanoose		Congestion was likely related to MEC Diamond Trail-Hills 345 kV line and Ottumwa Generation outages. (ITC)

Table 3.3-2: Outage Analysis of Study Flowgates

Final Results

The final results for the 2023 Near-Term Congestion study, as shown in Table 3.3-3, provides the changes in Adjusted Production Costs (APC) when ratings are increased for the identified flowgates.

Monitored Facility	State	Owner	APC Change ($M) *
Marblehead North 161/138 kV Transformer	IL	Ameren	-5.053
Johnson Junction – Graceville 115 kV	MN	GRE	-
Cayuga 345/230 kV Transformer	IN	Duke	2.064

Monitored Facility	State	Owner	APC Change ($M) *
Irvine – Beacon 161 kV	IA	Alliant West	0.396
Jefferson County – Woody 161 kV	IA	Alliant West	-0.139
Cayuga – Hillsdale North 230 kV	IN	Duke	0.487
Murphy Creek – Hayward 161 kV	MN	SMMPA/ALTW	1.021
Stone Lake 345/161 kV Transformer	WI	Xcel	0.159
Fox Lake – Rutland 161 kV	MN	SMMPA/ALTW	0.469
Woody – Appanoose	IA	Alliant West	0.382

Table 3.3-3: Final Results of Near-Term Congestion Study
*Positive numbers represent an economic benefit and negative numbers represent an economic loss

There were three flowgates of note in the final results of this study: Marblehead North 161/138 kV Transformer, Johnson-Junction-Graceville 115 kV, and the Cayuga 345/230 kV Transformer.

- Upgrades to the Marblehead North 161/138 kV Transformer create economic losses of approximately $5 million for the system in this study. Results also show that PJM and SPP see combined economic benefits of about $3 million from the upgrade at this transformer. Additional analysis is needed to understand the results and identify opportunities for coordination with MISO interregional and JTIQ teams.
- Upgrades to the Johnson Junction-Graceville 115 kV line result in no economic changes to the system. Analysis showed this line is located between two other limiting elements on the system that are preventing increased flow on the line even with an upgrade. Additional analysis of those nearby elements is needed to assess congestion relief opportunities for this line.
- Upgrades to the Cayuga 345/230 kV Transformer result in about $2 million of economic benefits. The upgrade allowed for reduced renewable curtailment on the system. PROMOD did not identify the Cayuga 345/230 kV as a binding constraint in the base model. Additional analysis is needed to identify how the PROMOD solution did not identify congestion but did find economic benefits to upgrading the facility.

Study Takeaways

The MISO economic planning process is geared towards long-term planning horizons rather than near-term planning horizons. In addition to adjustments that are needed in model development to better reflect the near-term, topology changes can shift or eliminate congestion making it challenging to use historical data to identify near-term issues and solutions.

Working with stakeholders to forecast future congested flowgates outside of historical day-ahead congestion may provide additional value. Additional analysis and coordination with MISO interregional and JTIQ may also provide some insight into issues identified in the 2023 Near-Term Congestion Study.

In 2023 Q4 MISO will publish a separate Near-Term Congestion Study Report with additional insight and context on the study process.

APPENDIX B

UPDATE ON MTEP23 NEAR-TERM CONGESTION STUDY

Update on MTEP23 Near-Term Congestion Study

Planning Advisory Committee

October 11, 2023

Purpose & Key Takeaways

Purpose:

Provide a final update on MTEP23 informational study to evaluate near-term congestion issues

Key Takeaways:

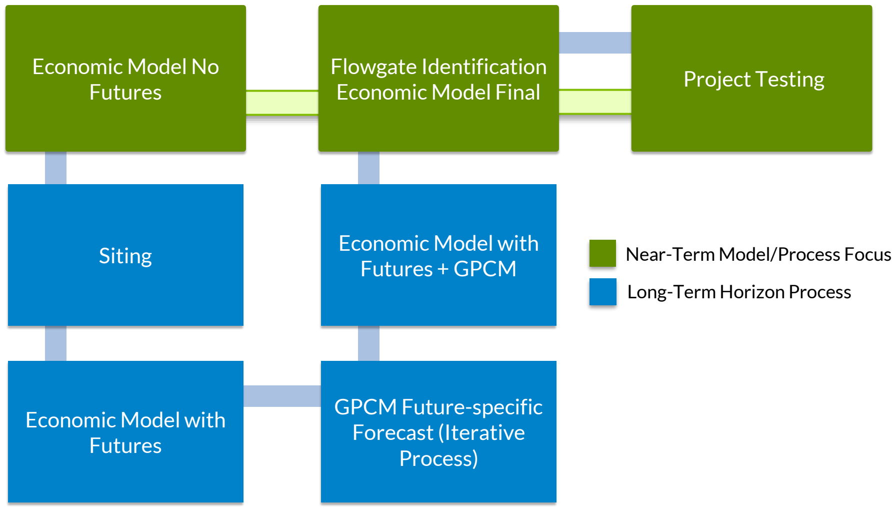
- MISO included an informational near-term congestion study in the MTEP23 scope
- Informational study reviewed historical, Day-Ahead (DA) congestion data and attempted to recreate congestion in MISO economic models to provide insight into potential economic benefits, measured by a change in Adjusted Production Cost (APC).
- MISO's economic model and processes are developed to inform long-term planning horizons and not near-term horizons. MISO will continue to explore how to adapt economic models and processes to identify near-term issues and solutions.

Takeaways from 2023 Near-Term Congestion Study

- Historic day-ahead congestion cost does not perfectly translate to MISO APC savings in economic models
  - Generation and transmission outages in real-time
  - Transmission system upgrades
  - Generator additions and retirements
- Working with stakeholders to forecast future congested flowgates outside of historical day-ahead congestion may provide additional value (ie long-term LRTP construction outage impacts)
- Some flowgates identified economic benefit to other entities along the seams but not within MISO may warrant additional coordination with JTIQ team
- Lessons learned on translating long-term economic planning processes to a near-term model

Issues identified under *PAC-2021-1 Address Congestion At Existing Resources*

Near-Term Congestion Economic Model Development and Study process is a subset of traditional MISO economic processes that are designed for long-term planning horizons



Near-Term Economic Model Overview

Economic Model No Futures

- Base model designed for Series 1A Futures study years 2027-2042 (Yr 5 – Yr 20)
  - Year 5 MTEP22 2027 Summer Peak Powerflow model includes approved future transmission projects that are not yet constructed and available to the market
  - Available generation includes new resources with signed GIA that are not yet constructed and available to the market

Flowgate Identification

- No flowgate identification was performed and instead the MTEP21 PROMOD Event File* was used as the base
  - Rating updates were applied to reflect MTEP22 Powerflow
  - New flowgate additions included the historical DA flowgates

Project Testing

- Simulated economic model to see if DA congestion could be duplicated under Year 5 assumptions (Base Case)
- DA constraints ratings were increased (emulates targeted fix) in the event file to determine if the economic model congestion provides MISO APC savings (Change Case)

*The event file is a PROMOD input file that sets transmission topology rules during simulation

 The Near-Term Congestion Economic Model steps include Economic Model No Futures Flowgate Identification, and Project Testing

Top 10 selected historical day-ahead congested flowgates and forecasted congestion in base economic model

Monitored Facility	State	Owner	2021 DA Congestion Cost	2022 DA Congestion Cost	Total	Base Economic Model Congestion Cost* (Yr 2027)
Marblehead North 161/138kV Transformer	IL	Ameren	$703,998	$102,380,057	$103,084,055	$283,232
Johnson Junction - Graceville 115 kV	MN	GRE	$52,940	$71,148,820	$71,201,761	
Cayuga 345/230kV Transformer	IN	Duke	$9,336,019	$30,302,338	$39,638,357	
Irvine - Beacon 161kV	IA	Alliant West	$6,657,585	$32,944,991	$39,602,576	
Jefferson County - Woody 161kV	IA	Alliant West	$7,918,644	$22,844,547	$30,763,191	
Cayuga - Hillsdale North 230kV	IN	Duke	$7,943,363	$21,985,302	$29,928,665	
Murphy Creek - Hayward 161kV	MN	SMMPA/ALTW	$341,855	$28,339,715	$28,681,570	
Stone Lake 345/161kV Transformer	WI	Xcel	$0	$28,385,411	$28,385,411	
Fox Lake - Rutland 161 kV	MN	SMMPA/ALTW	$14,660,581	$8,824,746	$23,485,327	
Woody - Appanoose 161kV	IA	Alliant West	$4,732,110	$18,366,834	$23,098,944	

*Annual average shadow price x number of binding hours

Near-Term Congestion Study final results simulate facility upgrades and identify possible economic impacts for MISO members through Adjusted Production Cost (APC) changes

Monitored Facility	State	Owner	APC Change ($M)*
			Near-Term Base
Marblehead North 161/138kV Transformer	IL	Ameren	-5.053
Johnson Junction - Graceville 115 kV	MN	GRE	-
Cayuga 345/230kV Transformer	IN	Duke	2.064
Irvine - Beacon 161kV	IA	Alliant West	0.396
Jefferson County - Woody 161kV	IA	Alliant West	-0.139
Cayuga - Hillsdale North 230kV	IN	Duke	0.487
Murphy Creek - Hayward 161kV	MN	SMMPA/ALTW	1.021
Stone Lake 345/161kV Transformer	WI	Xcel	0.159
Fox Lake - Rutland 161 kV	MN	SMMPA/ALTW	0.469
Woody - Appanoose 161kV	IA	Alliant West	0.382

*** Negative values represent economic losses to MISO, positive values represent economic benefits to MISO**

APC White Paper:
https://cdn.misoenergy.org/20210427%20PSC%20Item%2007%20MISO%20APC%20Calculation%20Methodology%20Whitepaper544059.pdf

Items under consideration for the 2024 Near-Term Congestion Scope

- Recreate congestion by removing topology and future resources with signed GIAs from model that was not in place when historical congestion occurred (ie Appendix A projects)
- Focus on flowgates with recreated historical congestion and potential for future near-term congestion
- Work with TO's to simulate critical outage scenarios that may cause persistent congestion
- Test ability to model upcoming LRTP Tranche 1 construction outages
- Consider working with TO's to identify upgrades to resolve congestion identified
- Evaluating drivers of APC changes when ratings are increased, considering impacts of nearby limiting elements
- Incorporate LRTP Tranche 1 and JTIQ projects into base case and examine any further benefit to the facility upgrades
- Coordinate with MISO operations to identify other near-term issues

Next Steps

- MISO will include a continuation of the Near-Term Congestion Study in the MTEP24 scope
  - MTEP24 scoping discussion is scheduled for the November 15, 2023 Planning Advisory Committee meeting
- Formal feedback request on 2024 Near-Term Congestion Study will come out in January 2024 for discussion at the January PSC
- Additional feedback on the 2024 Near-Term Congestion Study Scope can be provided at:
  - MISO Economic Planning Team: ep@misoenergy.org

Appendix

Historical congestion data was evaluated against outage data and additional information from facility owners

Monitored Facility	MISO Identified Outage Impacts	Additional Information from Facility Owner
Marblehead N. 161/138 kV Transformer	X	
Johnson Junction – Graceville 115 kV	X	The Johnson Junction to Graceville congestion issue was directly related to the planned construction outage on the Johnson Junction to Morris line which occurred between Oct 1,2021 and Feb 1, 2022. The normally open line segment north of Graceville was closed in to accommodate this construction outage leading to congestion on the Johnson Junction to Graceville line. Thus, the congestion correlates the construction of the Johnson Junction-Morris construction outage and grid reconfigurations. It is understood that when upgrading transmission facilities to accommodate the changing grid, it is often necessary to alter the normal operations of the transmission system which can lead to temporary economic congestion in order to ensure continued grid reliability. (GRE)
Cayuga 345/230 kV Transformer	X	Congestion was likely related to Cayuga Unit 1 outage and MTEP Project 22226 is expected to relieve this congestion. (Duke)
Irvine – Beacon 161 kV		Congestion was highly correlated to several outages including MEC Diamond Trail-Hills 345 kV, MEC Montezuma-Ottumwa 345 kV, and ITC Beacon-Tri County 161 kV line upgrade outages. Ottumwa Generation outages may have also increased congestion on the line. (ITC)
Jefferson County – Woody 161 kV		Congestion was likely related to MEC Diamond Trail-Hills 345 kV line and Ottumwa Generation outages. (ITC)
Cayuga – Hillsdale North 230 kV	X	Congestion was likely related to Cayuga Unit 1 outage and MTEP Project 22226 is expected to relieve this congestion. (Duke)
Murphy Creek – Hayward 161 kV	X	Congestion was likely related to XCL Crandall-Wilmarth 345 kV line upgrade outage and ITC Adams 161 kV bus outage to connect a new generator. (ITC) No evidence to suggest that any SMMPA outages impacted congestion at this flowgate. (SMMPA)
Stone Lake 345/161 kV Transformer		Facility owner confirmed minimal outage impacts. Congestion may have some relation to Manitoba Hydro flows. Congestion in 2023 has not been as extensive likely due to the refurbishment of the Eau-Claire - Arpin 345 kV line. MTEP Project 20229 is expected to further reduce binding on this line. (Xcel)
Fox Lake – Rutland 161 kV	X	Congestion was likely related to XCL Crandall-Wilmarth 345 kV and ITC-Lakefield-Dickinson County 161 kV line upgrade outages. (ITC) No evidence to suggest that any SMMPA outages impacted congestion at this flowgate. (SMMPA)
Woody – Appanoose		Congestion was likely related to MEC Diamond Trail-Hills 345 kV line and Ottumwa Generation outages. (ITC)

In the Matter of the 2025 Biennial Transmission Projects Report **MPUC Docket No. E999/M-25-99**

CERTIFICATE OF SERVICE

Michael Latana certifies that on the 9th day of May, 2025, he e-filed a true and correct copy the following document on behalf of Minnesota Transmission Owners via eDockets (www.edockets.state.mn.us):

1. Reply Comments.

Said document was also served as designated on the Official Service Lists on file with the Minnesota Public Utilities Commission and as attached hereto.

Executed on: May 9, 2025

Signed: /s/ Michael Latana
Fredrikson & Byron, P.A.
60 South Sixth Street
Suite 1500
Minneapolis, MN 55402

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron		60 S 6th St Ste 1500 Minneapolis MN, 55402-4400 United States	Electronic Service		No	Official 25-99
2	Generic	Commerce Attorneys	commerce.attorneys@ag.state.mn.us		Office of the Attorney General - Department of Commerce	445 Minnesota Street Suite 1400 St. Paul MN, 55101 United States	Electronic Service		Yes	Official 25-99
3	Ian M.	Dobson	ian.m.dobson@xcelenergy.com	Xcel Energy		414 Nicollet Mall, 401-8 Minneapolis MN, 55401 United States	Electronic Service		No	Official 25-99
4	Sharon	Ferguson	sharon.ferguson@state.mn.us		Department of Commerce	85 7th Place E Ste 280 Saint Paul MN, 55101-2198 United States	Electronic Service		No	Official 25-99
5	David R.	Moeller	drmoeller@fredlaw.com	Fredrikson & Byron, P.A.		60 S 6th St Ste 1500 Minneapolis MN, 55402-4400 United States	Electronic Service		No	Official 25-99
6	Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us		Office of the Attorney General - Residential Utilities Division	1400 BRM Tower 445 Minnesota St St. Paul MN, 55101-2131 United States	Electronic Service		Yes	Official 25-99
7	Christine	Schwartz	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall, MN1180-07-MCA Minneapolis MN, 55401-1993 United States	Electronic Service		No	Official 25-99
8	Julia	Selker	jselker@gridstrategiesllc.com	WATT Coalition		110 Allen St Suite A&B Cumming GA, 30040 United States	Electronic Service		No	Official 25-99
9	Will	Seuffert	will.seuffert@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul MN, 55101 United States	Electronic Service		Yes	Official 25-99
10	Adam	Sokolski	adam.sokolski@edf-re.com	EDF Renewable Energy		10 Second Street NE Ste 400 Minneapolis MN, 55410 United States	Electronic Service		No	Official 25-99