

February 2, 2026

PUBLIC DOCUMENT

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

RE: **PUBLIC** Comments of the Minnesota Department of Commerce
Docket No. E999/M-25-99

Dear Ms. Bergman,

Attached are the **PUBLIC** analysis and recommendations of the Minnesota Department of Commerce in the following matter:

In the Matter of the 2025 Minnesota Biennial Transmission Projects Report.

These comments address the GETs Report only. The Minnesota Department of Commerce (Department) filed separate comments on the BTPR on January 15, 2026.

The Department recommends **approval** and is available to answer any questions the Commission may have.

Sincerely,

/s/ Dr. SYDNIE LIEB
Assistant Commissioner of Regulatory Analysis

RP/DZ/AD/ar
Attachment

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ACRONYMS AND ABBREVIATIONS

AAR	Ambient Adjusted Ratings
ARR	Auction Revenue Results
ATT	Advanced Transmission Technologies
BESS	Battery Energy Storage System
BTPR	Biennial Transmission Project Report
CAISO	California Independent System Operator
CRR	Congestion Revenue Rights
DLR	Dynamic Line Rating
FERC	Federal Energy Regulatory Commission
FTRs	Financial Transmission Rights
GET	Grid Enhancing Technology
GNP	Grid North Partners
GRE	Great River Energy
IOU	Investor-Owned Utility
IPP	Independent Power Producer
LMP	Locational Marginal Pricing
L RTP	Long-Range Transmission Planning
MCC	Marginal Congestion Component
MISO	Midcontinent Independent System Operator
MP	Minnesota Power
MRES	Missouri Rivier Energy Services
MTEP	MISO Transmission Expansion Plan
MTO	Minnesota Transmission Owners
NSP	Northern States Power Company
OTP	Otter Tail Power
PFC	Power Flow Control
PPA	Power Purchase Agreement
TO	Topology Optimization
WECS	Wind Energy Conversion System

Before the Minnesota Public Utilities Commission**PUBLIC Comments of the Minnesota Department of Commerce**

Docket No. E999/M-25-99

I. INTRODUCTION

The Biennial Transmission Plan Report (BTPR) is submitted to the Minnesota Public Utilities Commission (Commission) every two years by the Minnesota Transmission Owners (MTO). The purpose of the BTRP is to identify transmission system inadequacies and plans to address each inadequacy. In 2025, the Commission ordered the Minnesota Transmission Owners to include a Grid Enhancing Technologies Report (GETs Report) in the 2025 BTPR.¹ The GETs Report identifies grid constraints that could benefit from a grid enhancing technology (GET) to reduce congestion. The GETs Report is required for any entity owning more than 750 miles of transmission lines in Minnesota.²

GETs are technologies that can be either hardware or software that reduce congestion or increase grid flexibility to respond to constraints in certain areas. The Department covered a range of GETs in its comments in Docket No. CI-24-318.³ The main commercially available and viable GETs are Dynamic Line Rating (DLR), Power Flow Control (PFC), and Topology Optimization (TO). These three technologies are identified in the GETs Law as technologies transmission line owners should consider using, but are not limited to, to address transmission inadequacies.⁴ While these three technologies are currently the most prevalent for addressing congestion, there are numerous other hardware and software implementations that transmission-owning entities could consider when addressing transmission congestion.

DLR are hardware installed on transmission lines that uses advanced heat transfer equations and takes time-interval readings of various environmental conditions, such as line temperature, wind speeds, line sag, and other localized conditions to get the real-time transmission line carrying capacity.⁵ PFC are technologies that efficiently direct the flow of electricity on the grid, mitigate overloads, and allow the grid to be more responsive.⁶ TO involves re-routing and reconfiguring network flows to mitigate transmission congestion and improve capacity.

¹ *In the Matter of the 2025 Minnesota Biennial Transmission Projects Report, Order*, Docket No. E999/M-25-99, September 10, 2025. (eDockets) [20259-222888-01](#) (hereinafter “September 10, 2025 Order”).

² [Laws of Minn. 2024, ch. 127, art.42, sec 52.](#)

³ *In the Matter of the Investigation into Transmission-Curtailment Matters, Drivers, and Potential Solutions to Limitations Resulting from the Nobles County Substation*, Minnesota Department of Commerce, Comments, Docket No. E-999/CI-24-316, October 23, 2024, (eDockets) [202410-211261-02](#)

⁴ [Laws of Minn. 2024, ch. 127, art.42, sec 52.](#)

⁵ Gentle, Jake, S.M. Shafiul Alam, Mucun Sun, Zach Priest & Becca Avery, *Grid Enhancing Technologies*, Idaho National Laboratory (November 2024). Available at: https://inl.gov/content/uploads/2024/03/POWER_Grid-Enhancing-Technologies.pdf.

⁶ Gentle, Jake, S. M. Shafiul Alam, Mucun Sun, Zach Priest, Alberto Del Rosso, Dan Schweer & Swaroop Guggilam. *Implementation and Operation of Power Flow Control Solutions for Transmission Systems*. Idaho National Laboratory, (November 2024). Available at: <https://inl.gov/content/uploads/2024/03/Implementation-of-PFC-solutions.pdf>.

II. PROCEDURAL BACKGROUND

March 24, 2025	The Commission orders ⁷ the MTO to include a cost-benefit analysis in their 2025 Biennial Transmission Report comparing any feasible battery storage solution to status quo conditions, and to include an update on large wind energy systems (WECS) curtailment and economic impact for the Nobles County substation area and the areas of congestion identified as part of the GETs study.
September 10, 2025	The Commission orders ⁸ MTO to file the GETs report as part of the BTPR including calculations for the cost effectiveness for each potential GET.
October 31, 2025	The MTO files BTPR ⁹ and the GETs Report. ¹⁰
November 10, 2025	The MTO filed a variance request for the comments deadlines for the GETs Report comment period. ¹¹
November 12, 2025	The Commission filed a Notice of Comment Period for the GETs report. ¹²
November 26, 2025	The Commission filed an order approving the rule variance to the notice of comment schedule for the GETs report. ¹³

Topic(s) open for comment:

1. Is the 2025 Grid Enhancing Technologies Report (GETs Report) complete? [Note: Per rule, challenges to completeness must be received within 20 days of the initial filing.] In other words, does the report contain all information required by the following:
 - a. The 2024 GETs Law¹⁴ and Minn. Stat. §216B.2425, Subd 2

⁷ *In the Matter of the Investigation into Transmission-Curtailment Matters, Drivers, and Potential Solutions to Limitations Resulting from Nobles County Substation, Order Establishing Filing Requirements*, March 24, 2025, Docket No. E-999/CI-24-316, (eDockets) [20253-216722-01](#) (hereinafter “March 24, 2025 Order”).

⁸ September 10, 2025 Order.

⁹ *In the Matter of the 2025 Minnesota Biennial Transmission Projects Report*, Minnesota Transmission Owners, 2025 Biennial Transmission Projects Report, October 31, 2025, Docket No. E999/M-25-99, (eDockets) [202510-224474-02](#). (hereinafter “BTPR”).

¹⁰ *In the Matter of the 2025 Minnesota Biennial Transmission Projects Report*. Minnesota Transmission Owners, Grid Enhancing Technologies Study Report, October 31, 2025, Docket No. E999/M-25-99, (eDockets) [202510-224474-04](#) at Appendix B (hereinafter “GETs Report”).

¹¹ *In the Matter of the 2025 Minnesota Biennial Transmission Projects Report*, Minnesota Transmission Owners, Letter for Schedule Variance Request, November 11, 2025, Docket No. E999/M-25-99, [202511-224818-01](#) (eDockets).

¹² *In the Matter of the 2025 Minnesota Biennial Transmission Projects Report, Notice of Comment Period and Establishment of Service List*, November 12, 2025, Docket No. E-999/M-25-99, (eDockets) [202511-224871-01](#). (hereinafter “Notice”)

¹³ *In the Matter of the 2025 Minnesota Biennial Transmission Projects Report, Order*, Docket No. E999/M-25-99, November 26, 2025, (eDockets) [202511-225327-01](#).

¹⁴ [Minnesota Session Laws, 2024, Chapter 127, Article 42, Section 52.](#)

- b. The Commission’s March 24, 2025, Order in Docket No. E999/CI-24-316¹⁵
 - c. The Commission’s September 10, 2025, Order in Docket No. E999/M-25-99¹⁶
 2. Should the Commission approve, reject, or modify Minnesota Transmission Owners’ GETs implementation plans?
 3. For future GETs Reports: should the Commission add or modify the filing requirements? Topics of interest to the Commission include:
 - a. How to calculate the payback period
 - b. Accounting for Financial Transmission Rights revenues
 - c. The payback period threshold(s) used to develop implementation plans
 - d. Comparing combinations of grid enhancing technologies with traditional upgrades
 - e. New or emerging GETs technologies
 4. Are there other issues or concerns related to this matter?

III. DEPARTMENT ANALYSIS

A. RELEVANT DOCKETS AND STATUTES

A.1. GETs Law and Minn. Stat. § 216B.2425, subd. 2

As required by the Minnesota Legislature and Commission Order, the GETs Report is required to be filed by any entity that owns or operates more than 750 miles of transmission line in Minnesota. The report reviews historical congestion trends and determines possible GETs solutions and implementation plans when practicable. Any area experiencing congestion more than 168 hours of the year over a three-year historic lookback is subject to inclusion in the GETs Report. As discussed in “Section B. List of Proposed Projects,” the report includes material provided by the five transmission-owning utilities that own more than 750 miles of transmission lines, and three additional utilities that jointly own facilities.¹⁷ The utilities identified 66 constraints that meet the requisite threshold of 168 hours. The Department finds this component complete, based on the requirements listed in the GETs Law¹⁸ and Minn. Stat. § 216B.2425, subd. 2.

The Department focused considerable attention on the payback period, which is the calculation for deciding whether a proposed GETs solution is cost-effective, relative to its costs. The payback methodology and threshold are the critical standards determining which GETs solutions are viable for implementation. Further discussion of the enabling GETs Law can be found in the Department’s discussion section “D.2, Calculating the Payback Period.”

A.2. PUC’s March 2025 Order in Docket No. E999/CI-24-316

In Docket No. E-999/CI-24-316, the Commission ordered transmission owners to include a “cost-benefit analysis in their Biennial Transmission Projects Report that compares any feasible battery

¹⁵ March 24, 2025 Order.

¹⁶ September 10, 2025, Order.

¹⁷ GETs Report at 4.

¹⁸ [Minnesota Session Laws, 2024, Chapter 127, Article 42, Section 52.](#)

storage solution to status quo conditions and to its performance under planned upgrades at the Nobles County substation area.”¹⁹ The Battery Storage Study is attached as Appendix C of the 2025 Biennial Transmission Projects Report, and Appendix D references the System Impact Study for the Nobles BESS.²⁰ In Appendices C and D, the MTO proposes a battery energy storage system (BESS) and a traditional upgrade for a new transformer were proposed to address congestion and curtailment for the Nobles County substation in southwestern Minnesota.²¹ In the System Impact Study, Xcel Energy found that, if the BESS were charged at times when wind was curtailed, the BESS would save an estimated 240,257 megawatt-hours (MWh) of curtailed electricity, which represents about 25% of curtailment in Nobles County. The Department also notes that Xcel Energy also recently filed a request for expedited interconnection for the 300 MW Nobles County BESS project in the expedited generator-interconnection queue at the Midcontinent Independent System Operator (MISO), known as the Expedited Resource Addition Study (ERAS).²² The Department finds these appendices satisfy the Commission’s March 24, 2025 Order for Order Point 1.

The March 24, 2025 Order also specifies that the MTO shall include an update of WECS curtailment and economic impact at the Nobles substation.²³ There is limited discussion in the GETs Report of wind generation development contributing to congestion and increased pressure on transformers in Nobles and Lyon County. **[TRADE SECRET DATA HAS BEEN EXCISED]** The MTO could consider further discussion of WECS curtailment, as curtailment creates other costs for ratepayers which could be factored into any payback methodology, including any curtailment payments a utility may make, expensive market purchases of replacement energy, or other external costs. The Department discusses this further in section “D.2, Calculating the Payback Period.”

A.3. Does the GETs Report Contain the information from the Commission’s September 2025 Order, Docket No. E999/M-25-99?

In the Commission’s September 10, 2025 Order, the MTO is required to include a “schedule and cost estimate to install grid enhancing technologies at each congestion point identified at which the payback period is less than or equal to five years.”²⁴ Order Point 2 states that the transmission owners shall “provide workpapers showing calculations and how each input was quantified.”²⁵ **[TRADE SECRET DATA HAS BEEN EXCISED]**

¹⁹ *In the Matter of the Investigation into Transmission-Curtailment Matters, Drivers, and Potential Solutions to Limitations Resulting from the Nobles County Substation, Order Establishing Filing Requirements*, March 24, 2025, Docket No. E999/CI-24-316, (eDockets) [20253-216722-01](#) (hereinafter “Nobles Curtailment Order”).

²⁰ *In the Matter of the 2025 Minnesota Biennial Transmission Projects Report*. Minnesota Transmission Owners, Appendix C, Xcel Energy Nobles Battery Study 2025 and Appendix D System Impact Study Project Nobles BESS. October 31, 2025, Docket No. E999/M-25-99, (eDockets) [202510-224474-06](#). (hereinafter “Nobles BESS Study”)

²¹ Nobles BESS Study at 2.

²² MISO, *Expedited Resource Addition Study (ERAS) ERAS Interconnection Requests*. MISO, (last visited January 15, 2026) [ERAS Interconnection Requests_011626.xlsx](#).

²³ Nobles Curtailment Order at Order Point 2.

²⁴ September 10, 2025 Order.

²⁵ *Id.*, at Order Point 2.

The Department notes the MTO provided workpapers and other materials required to complete the Department's analysis upon request. The Department notes that all workpapers needed to complete its analysis be included in MTO's initial filing. With the addition of the work papers provided by MTO, the Department finds this requirement complete.

Because the Department received a large amount of data on January 9, 2026 and January 14, 2026, the Department is still analyzing data on financial transmission rights (FTRs). The Department includes some analysis of FTR profits and congestion charges in these comments and will provide further analysis of Auction Revenue Rights/Financial Transmission Rights (ARR/FTR) data in future reply and supplemental comments.

B. LIST OF PROPOSED IDENTIFIED CONSTRAINTS

The report identifies 66 constraints that meet the congestion threshold of 168 hours in the previous three years (2022-2024). Of those, the MTO grouped the constraints, according to their cause and relative ability to address the congestion, given the utility derived payback period and length of congestion. The Department lists the 66 constraints identified in the GETs Report and their relevant classifications for analysis of congestion constraints:

- 12 constraints were identified that met the relevant payback period (either with GETs, traditional upgrades, or a combination of both).
- 7 constraints had identified solutions but needed additional analysis to determine if payback period was met.
- 2 constraints had no solutions identified.
- 2 constraints had solutions identified but did NOT meet the payback periods threshold.
- 18 constraints have already had projects completed within the past three years, or have planned upgrades that were already developed prior, and are already part of past, present, or future MISO Transmission Expansion Plan (MTEP) processes.
- 17 constraints are caused by temporary outages or certain operating conditions which, due to being unique or very time-bracketed, solutions were not identified.
- 8 constraints were identified as having high congestion in future models, which MTO indicated that it would continue to monitor for future inclusion for GETs implementation.

The "constraints with completed or pending projects" category indicates a GETs project has been completed, or the MTO proposed a cost estimate and schedule for a GET. The MTO only proposes 12 new GETs in the 2025 GETs Report. The other 18 solutions considered were already decided after consultation with the Grid North Partners (GNP) working group upon completion of the 2023 Biennial Transmission Projects Report.²⁶ The 18 constraint solutions provided by GNP, plus the 12 constraint

²⁶ *In the Matter of the 2023 Biennial Transmission Projects Report, Order Accepting Report*, June 7, 2024, Docket No. E - 999/M-23-91, (eDockets) [20246-207503-01](#), at 4.

solutions from the 2025 GETs Report, equal 30 constraints that have either been completed, will be completed, or have a solution that meets the payback period.

Table 2 highlights the 12 projects that have constraints that can be addressed by a GET and meet the payback solutions threshold. The Department separates the constraints that meet the solutions threshold by whether the solutions are traditional upgrades or specific GETs implementations.

[TRADE SECRET BEGINS]

Table 1: Constraints with Solution Proposals, Payback Period Met

[TRADE SECRET DATA HAS BEEN EXCISED]

[TRADE SECRET DATA HAS BEEN EXCISED]

Of the 18 constraint solutions that are complete or pending completion from the 2023 BTPR, **[TRADE SECRET DATA HAS BEEN EXCISED]**. The business structure for investor-owned utilities (IOUs), may create more incentives to develop upgrades that require more capital-intensive infrastructure. In the GETs Report framework, this incentive structure could lead the investor-owned transmission-owning utilities within the MTO to prefer traditional solutions over GET solutions to earn a higher rate of return.

The Department believes that including these 18 constraints was not necessary or relevant, **[TRADE SECRET DATA HAS BEEN EXCISED]** The MTO know where congestion occurs and can identify which constraints require upgrades to maintain reliability, but many of the MTO did not fully consider GETs until the GETs law was passed. Many of the 18 constraints were identified in MISO Transmission Expansion Plan (MTEP) cycles and were not studied by the Department or Commission to understand the costs or benefits to Minnesota ratepayers.

In addition to the 12 projects listed in Table 1, the MTO includes seven projects with constraints and identified solutions, but no payback period determined yet.

The **Department requests** MTO provide the workpapers or other information on the payback period of these seven projects that do not yet have payback period determined in their reply comments. In the case that projects are disqualified from consideration, the Department requests a discussion from MTO for why they fail to consider GETs implementation for the proposed constraint.

MISO developed the Long-Range Transmission Plan (LRTP) Tranche 1 and Tranche 2.1 portfolios, which aim to increase reliability in the Midwest and Minnesota, of which the MTO were stakeholders. In the short-term, the MTO highlights that Tranche projects can increase congestion because they require lines to be rebuilt or because new generation is interconnecting to the grid. In the long term, Tranche projects are expected to relieve congestion by adding more capacity to lines. Tranche 2.1's 765 kV transmission "backbone" was developed specifically for the congestion and reliability concerns of aging infrastructure. Including DLR and other GETs to curb congestion could help with future congestion as planned outages increase due to Tranche development.

C. FINANCIAL TRANSMISSION RIGHTS

The Commission's September 10, 2025 Order requires the MTO to account for FTRs in the GETs Report.²⁷ FTRs are financial tools in the wholesale MISO market that allow a transmission owner (or one who holds FTRs for particular transmission segments) to hedge against congestion and profit from congestion between two nodes. An FTR entitles the holder to a settlement equal to the difference in the marginal congestion component (MCC) of the locational marginal price (LMP) between the sink and source nodes. When congestion occurs in the direction of the FTR, this settlement results in a payment to the FTR holder. When congestion occurs in the opposite direction, the same settlement mechanism results in a charge to the FTR holder, who must pay MISO. Thus, FTRs can produce either revenues or charges depending on the realized congestion pattern. The GETs report must account for all FTR profits for each constraint's congestion charge, to ensure the full costs of transmission congestion are accounted for.

To calculate congestion charges, the MTO adapted a methodology developed by the California Independent System Operator (CAISO) Department of Market Monitoring for allocating revenue inadequacy in their Congestion Revenue Rights (CRR) Market by constraint to CRR holders.²⁸ The advantage of this methodology is that it adjusts congestion charges to reflect the financial hedging provided by FTRs. Specifically, congestion costs incurred by load are netted against realized FTR profits or losses, so that the reported congestion charge represents the residual congestion exposure after FTR settlements.

The report includes adjusted FTRs rather than unadjusted FTRs. The adjusted FTRs indicate instances where the congestion has been successfully financially hedged, netting for any positive revenues above the charges. The MTO decided to manipulate the FTR data to make congestion appear as a negative attribute to the system.²⁹ However, the PUC Order states that "Transmission owners shall calculate the cost of historical congestion using the congestion charge (\$) of the constraint after netting the revenue of ARR/FTRs that are associated with the constraint."³⁰ The Department asserts that the unadjusted

²⁷ September 10, 2025 Order at Order Point 3.

²⁸ Department of Market Monitoring, *Allocating CRR Revenue Inadequacy by Constraint to CRR Holders*. California ISO. (October 6, 2014). Available at <https://www.caiso.com/Documents/AllocatingCRRRevenueInadequacy-Constraint-CRRHoldersDMMWhitePaper.pdf>.

²⁹ Attachment C.

³⁰ September 10, 2025, Order at Order Point 3.

revenue from ARR/FTRs provide better insight into the full costs of congestion relative to the revenues received from financial ownership of transmission and any financial hedging.

The Department does not agree with the approach of truncating adjusted congestion charges at zero when FTR revenues exceed gross congestion costs. In organized electricity markets, FTR settlements are designed to financially hedge congestion exposure, such that positive FTR revenues offset congestion charges and FTR losses increase net congestion costs borne by customers. Allowing adjusted congestion charges to be either positive or negative, more accurately reflects how congestion risk is managed and allocated in practice. In cases where FTR revenues exceed congestion charges, this outcome indicates that congestion resulted in a net financial gain to the system rather than a zero-cost outcome. For example, if a constraint incurs a congestion charge of (\$100,000) and associated FTR revenues of \$150,000, the net congestion outcome is a gain of \$50,000. Setting the adjusted congestion charge to zero in such instances masks this result and understates the full economic impact of congestion and hedging activity.

When congestion occurs in the prevailing flow direction of the contract, it results in positive FTR revenues. However, if congestion materializes in the counterflow direction, the FTR can instead generate charges, which require payments to MISO and increase net costs. Because FTRs can both offset and amplify congestion costs depending on system conditions, the Department requested the MTO's unadjusted FTR revenues and charges by contract to fully capture congestion outcomes under both prevailing and countervailing flows. This transparency is important because the Payback Period Solutions rely on a three-year average of congestion charges net of FTR revenues; understanding the gross components ensures that hedging performance and congestion risk are accurately represented.

In Tables 2-6 and Figures 1-5, the Department used the data provided by the MTO to calculate net revenues for each MTO that shared data from their holding of FTRs.³¹ The Department identified all contracts for which FTR revenues are positive (meaning congestion occurred in the prevailing flow direction), wherein the transmission owner holding the FTR would be paid by MISO. The Department then added all instances where FTR revenues are negative (congestion materialized in the counterflow direction), wherein the FTR holder would pay MISO for the congestion, giving the annual sum of FTR revenues for each year from 2022-2024. The Department calculated the net revenues for all the MTO that provided us with the necessary data.

- Table 2 and Figure 1 highlight FTR data provided by Xcel Energy (NSP)
- Table 3 and Figure 2 highlight FTR data provided by Great River Energy (GRE)
- Table 4 and Figure 3 highlight FTR data provided by Otter Tail Power (OTP)
- Table 5 and Figure 4 highlight FTR data provided by Minnesota Power (MP)
- Table 6 and Figure 5 highlight FTR data provided by Missouri River Energy Service (MRES)

³¹ Attachment D.

[TRADE SECRET DATA HAS BEEN EXCISED]

A challenge in developing the FTR netting methodology was allocating FTR profits to individual binding constraints to offset reported congestion charges at the constraint level. To address this challenge, the MTO adapted an approach described in a white paper produced by the California Independent System Operator (CAISO). The MTO modified the underlying equations to apply MISO FTR revenue data, rather than CAISO Congestion Revenue Rights (CRR) payments, using source and sink shift factors to distribute congestion revenues to specific constraints. The MTO only considered FTRs owned by utilities for this report, which reflects a partial FTR adjustment. The Department acknowledges that this proposed calculation represents an initial iteration of a new analytical framework; the Department also notes the MTO's statement that complete FTR information for all MISO market participants was not available is not accurate. Based on subsequent discussions and review between Department staff and the MTO, the Department finds that publicly available MISO auction results and Day-Ahead LMP data allows for the calculation of FTR revenues across all market participants. The Department encourages future studies to consider a broader set of publicly available FTR information to improve the completeness and robustness of the congestion analysis.

*D. DISCUSSION TOPICS LISTED IN THE NOTICE**D.1. Completeness*

The Department submitted its comments on completeness for the BTPR, of which Appendix B is the GETs Report.³² In those comments, the Department did not address any merits relating to the completeness of the Report.³³ Upon further analysis, the Department notified the MTO about the lack of working papers showing their calculations of the GETs Solutions and Production Cost Savings to derive the payback period. Based on its review of the filing and the information in the record, including the working papers provided by the MTO on January 9, 2025 and January 14, 2025, the Department finds the GETs Report complete.³⁴

The Department appreciates the material provided by the MTO.³⁵ The Department also recommend the MTO include the same information as is presented in the Department's Table 1, (GETs Solutions Cost, three-year average congestion charge, and Payback Period) into their first summary table of the identified constraints to allow for easy comparison between GETs, and to provide better insight for why a particular GET was not feasible for a given congestion constraint. The Department also recommends including more data overall in its workpapers, such as underlying congestion and GET modeling assumptions, solutions costs, and unadjusted congestion charges. This additional workpaper data will allow the Department and other stakeholders to identify whether financial hedging or physical hedging nets more benefits for a given constraint.

³² *In the Matter of the 2025 Minnesota Biennial Transmission Projects Report*, Minnesota Department of Commerce, Comments on Completeness, November 19, 2025, Docket No. E999/M-25-99, (eDockets) [20261-226962-01](#).

³³ *Ibid.*

³⁴ Attachments A – D.

³⁵ *Ibid.*

The **Department recommends** that future GETs Reports include working papers that include derivations of all calculations as a separate appendix.

D.2. Calculating the Payback Period

The payback period calculation is based on the GETs Solution Cost (numerator) and Adjusted 3-Year Average Congestion Charge (denominator) for a given constraint. Congestion charges are used to decide whether a GET is implemented, with the GET's payback evaluated against the transmission owner's ability to financially hedge congestion.

[TRADE SECRET DATA HAS BEEN EXCISED]

The Department finds that the three-year average adjusted congestion charge is an incomplete measure of the overall payback period. GETs provide substantial value to ratepayers that are not captured by the current methodology. These benefits include avoided costs from curtailment and avoided market purchases of replacement energy. By reducing curtailment, GETs also help prevent losses in production tax revenue for counties. More broadly, GETs deliver value by physically mitigating congestion on the transmission system, creating avoided costs beyond profits associated with financial hedging or FTRs. These benefits should be accounted for when evaluating GET implantation plans.

An illustration of these unaccounted costs is in areas where utilities may have PPAs for generation near transmission lines where they have active FTRs, the transmission-owning utility could have other payments to make when there is congestion, such as replacement energy or curtailment payments. In these cases, the positive revenues of FTRs would be lessened by any curtailment payments, and any negative FTR revenues would be amplified by additional payments that are caused by curtailment and congestion.

The cost of implementing a GET should include financial hedging of transmission congestion and be connected to the revenues and charges generated by the same congestion in a secondary market. However, there are tangible benefits to be gained from physically addressing congestion with GETs that are not considered in the current utility derived payback methodology. For example, increasing transmission capacity could reduce curtailment of renewable energy resources, specifically wind and solar, and avoid curtailment costs to counties that host renewable energy infrastructure. Additionally, the MTO who are in PPAs with wind developers might have to pay independent power producers (IPPs) for curtailed energy. The avoided payments to IPPs, along with avoided costs of replacement energy further showcase the benefits of addressing physical congestion compared to just relying on financial hedging.

The **Department requests** the MTO to provide in reply comments any information they have about PPAs or curtailment payments to generators on transmission lines where the MTO also hold FTRs.

The methodology currently proposed by the MTO fails to factor in multiple potential positive externalities to physically addressing congestion constraints, over solely successfully hedging congestion. Because the MTO's current methodology bases the payback period exclusively on average

adjusted congestion charges, it may understate the value of physically mitigating congestion, particularly in reducing exposure to extreme and volatile congestion costs. A more comprehensive assessment should therefore incorporate additional metrics, including avoided costs associated with preventing severe congestion events and reducing congestion volatility over time. Specifically, any evaluation should account for the variability and tail risk in congestion costs, including high-congestion years, event-driven congestion, and periods in which FTRs perform poorly or result in net charges due to counterflow conditions.

Local communities that host energy and grid infrastructure in grid constrained areas will also benefit from deployment of GETs. While GETs can solve physical congestion issues—and therefore deliver energy and associated tax benefits to host communities—financial instruments that merely patch over the fiscal risk of congestion losses benefit only transmission owners.

The **Department recommends** the Commission order the MTO to calculate the benefits of GET implementation that include the range of outcomes that would result from physical solutions to congestion rather than the outcomes that result from the application of financial instruments.

D.3. Accounting for Financial Transmission Rights Revenues

The Commission expressed interest in the MTO identifying congestion charges offset by FTRs to understand whether the transmission owners are successfully financially hedging their congestion risk, thus minimizing the impact to ratepayers from transmission congestion. The Department investigated whether the MTO could address congestion, and the burden congestion causes on ratepayers, using financial hedging, rather than physically addressing congestion with a GET). From its investigation, the Department found that the MTO had varying degrees of success with financial hedging for congestion.

[TRADE SECRET DATA HAS BEEN EXCISED]

The MTO also only examined financial hedging via FTRs in areas with congestion of 168 hours or more per year, on average, for the last three years. However, it is possible that there are areas experiencing lower hourly congestion, on a yearly basis, than 168 hours that experience more volatile congestion pricing. For example, a 115kV that experiences 250 hours of congestion per year may have lower volumes of line carrying capacity, making the financial impact of the congestion less, while a 345 kV that experiences 50 hours per year has larger financial impact from congestion. This level of detail is not present in the GETs Report.

Examining areas where congestion occurs based on their financial impact, rather than hours of congestion experienced, could significantly change financial hedging results. In future comments, the Department will investigate whether the methodology for inclusion in the GETs Report (such as the 168 hours or more, on average, congestion per year) is the right cutoff for including in the GETs Report. Though the legislative requirement for the report has 168 hours or more of congestion as one threshold for inclusion, the Commission may include an additional threshold for inclusion in the GETs Report, such as the overall costs of congestion.

The Department notes that the current net congestion charge calculations account only for FTRs held by the MTO, even though FTR activity across the entire MISO footprint affects congestion outcomes and the effectiveness of financial hedging. Publicly available MISO auction results and Day-Ahead LMP data suggest that FTR revenues and charges for all market participants could be incorporated to provide a more complete picture of how congestion is financially managed in the market.

To enable comparison of utility-specific FTR performance, relative to systemwide hedging outcomes in future reports, the **Department recommends** that the Commission order the MTO to include separate reports of both FTRs held by the MTO and FTRs held by all MISO market participants.

D.4. Payback Period Thresholds used to Develop Implementation Plans

[TRADE SECRET DATA HAS BEEN EXCISED] The Department is interested if any additional GETs could meet the payback period threshold under Order Point 4c from the Commission's September 10, 2025 Order, which states that transmission owners will include in their November 2025 Report "a schedule and cost estimate to install grid enhancing technologies at each congestion point identified at which the payback period is less than or equal to a value appropriate to the specific technology and potential application."³⁶ There could be additional GET implementations that do not meet the five-year threshold, but do meet a value that is "less than or equal to a value appropriate to the specific technology."³⁷ Not only does Order Point 4c encourage the MTO to look for GET solutions beyond the five-year payback period, it also acknowledges that newer or emerging technologies might not fit the five-year payback period. The Order Point leaves the door open for the payback period to be reevaluated in future reports and differentiated by different technologies.

It might not be beneficial to analyze some GETs using the five-year payback period threshold. GETs such as PFC or TO are software that could increase system flexibility and increase capacity. **[TRADE SECRET DATA HAS BEEN EXCISED]**

In addition to the type of GETs explicitly named in the report, there are other technologies that would likely not meet the five-year payback threshold but could have positive outcomes. Advanced conductors are one example. FERC Order 2023 relates to transmission planning and incorporating new technologies into the interconnection queue process, including increasing flexibility and incorporating alternative transmission technologies.³⁸ The Order addresses the link between increasing transmission capacity and includes alternative transmission technologies (ATTs) that go beyond the GETs listed for inclusion in the GETs Report and include advanced conductors, static synchronous condensers, and other technologies.³⁹ A recent report from Energy Innovation Policy and Technology found that advanced reconductoring can result in real-world doubling of existing transmission capacity within

³⁶ September 10, 2025 Order.

³⁷ *Ibid.*

³⁸ Federal Energy Regulatory Commission. *Improvements to Generator Interconnection Procedures and Agreements*. Federal Register. April 16, 2024. Available at <https://www.federalregister.gov/d/2024-06563/p-1720>

³⁹ *Ibid* at para 588.

existing rights of way.⁴⁰ While the upfront capital costs are higher for advanced reconductoring than most GETs, these types of projects could have additional benefits, beyond alleviating congestion charges, such as contributing to reliability, increasing transmission line capacity, and providing more re-routing opportunities for optimizing flows.

The following example illustrates the use of an advanced reconductoring project as a GET solution. Suppose a project in the Constraints with Solution Proposals (Payback Period Not Yet Determined) has an estimated solutions cost of \$20 million to implement advanced reconductoring and has benefits of \$3.9 million per year. The payback period for this project would be 5.13 years and, according to the five-year threshold methodology, would not be implemented. This methodology favors projects that simply meet the five-year payback threshold, so projects with significantly less benefits that do meet the five-year threshold might be included over projects that have more benefits but also have higher costs. This approach could leave out valuable GETs that are more cost effective than traditional transmission upgrades

The five-year threshold fails to include projects that have major benefits but are relatively expensive since the technology is new or emerging. For example, a GET upgrade that only costs \$1 million with benefits of \$15,000 per year, would not meet the Commission's threshold. This is problematic since many GET upgrades address the "low hanging fruit" grid constraints to provide quick and inexpensive upgrades, compared to traditional solutions. But if a GET is new or emerging and still reaching for economies of scale, it could take years for a viable and useful technology to meet the five-year threshold.

Within the GETs Report, the MTO highlight numerous constraints that do not meet solutions payback thresholds for implementing a GET. Considering the broader qualification for inclusion of GET based on a payback period "less than or equal to a value appropriate to the specific technology and potential application," there could be many constraints identified in the GETs Report that are eligible for GETs implementation with this broad definition for the payback period.⁴¹ For any constraints that do not yet have an identified solution, there could be GETs solutions that still qualify for inclusion and implementation.

The Department recommends either:

The Commission require the MTO put forth cost estimates and schedules for GETS solutions for any constraints that do not currently meet the five-year payback and instead apply a payback period threshold appropriate to that specific technology.

OR

⁴⁰ Chojkiewicz, Emilia, Umed Paliwal, Nikit Abhyankar, Casey Baker, Ric O'Connell, Duncan Callaway, and Amol Phadke. *2035 and Beyond: Reconductoring With Advanced Conductors Can Accelerate the Rapid Transmission Expansion Required for a Clean Grid*. GridLab, (June 2024). At 18. Available at: https://www.2035report.com/wp-content/uploads/2024/06/GridLab_2035-Reconductoring-Technical-Report.pdf.

⁴¹ September 10, 2025 Order.

The Commission create payback period thresholds for each specific GET, including, but not limited to, dynamic line rating, power flow control, topology optimization, and advanced reconductoring. Lastly, the **Department recommends** that the Commission order the MTO to provide cost estimates and implementation timelines for solutions using the appropriate payback period.

D.5. Combinations of GETs with Traditional Upgrades

[TRADE SECRET DATA HAS BEEN EXCISED] In instances where the MTO consider proposing formal transmission upgrades rather than GETs, the MTO should compare the cost-effectiveness and timeline against GETs to address congestion. The MTO should consider whether GETs can offset or delay expensive system upgrades, until larger backbone reliability projects, like MISO Tranche 1 and Tranche 2.1 can reach commercial operation and mitigate congestion through more transmission capacity.

[TRADE SECRET DATA HAS BEEN EXCISED] The Department is not proposing deferral of formal transmission upgrades the utilities propose for the strength and reliability of the grid. The Department finds that GETs do not significantly increase prices of traditional upgrades when they are paired together.

The GETs report characterizes the use of AAR as an upgrade and solution to transmission constraints. This framing is not entirely accurate, since FERC Order No. 881 requires transmission providers to implement AAR as a baseline compliance obligation. Therefore, incorporating AAR does not represent an alternative to a traditional upgrade, but rather a FERC required upgrade that would occur regardless of the MTO implementation plans in GETs Report. FERC Order No. 881 was approved in 2021 and requires all transmission providers to use AAR by July 2025.⁴² Because AAR are required by FERC, they should not be considered as a novel GET solution or upgrade to mitigate congestion. Therefore, AAR should not be considered in the MTO's GET implementation plans in future reports.

The **Department recommends** that GETs are considered during the construction of transmission lines and any planned outages from MISO's Tranche 1 and Tranche 2.1 LRTP.

The **Department also recommends** that, where feasible and where costs would not significantly increase, the MTO consider adding GETs to any proposed traditional upgrades.

Lastly, the **Department recommends** the Commission order that ARR are ineligible for inclusion in future GET report implementation plans.

D.6. New or Emerging Grid Enhancing Technologies

New technologies and innovations are constantly being developed to address grid reliability and energy affordability. The GETs described in the 2026 report provide insight into the technologies currently being used, but the report fails to identify new or emerging technologies that are still in the

⁴² Federal Energy Regulatory Commission (FERC). *Managing Transmission Line Ratings*, Order No. 881-A. Federal Register. Available at [Federal Register :: Managing Transmission Line Ratings](#).

“start-up” phase or only being used in certain parts of the country or world. A discussion of new or emerging technologies would help to address constraints that may not have easily addressed solutions or constraints from punctuated outages of new transmission buildout or repairs. Additionally, it could provide opportunities for the MTO to propose pilot programs for cutting-edge GETs implementations.

The **Department recommends** that future GETs Reports include a discussion of new or emerging GETs, and the possibility of developing GET pilot projects.

IV. DEPARTMENT RECOMMENDATIONS

Based on analysis of the information in the record, the Department has prepared recommendations, which are provided throughout the Department’s analysis and reproduced below for clarity:

D. DISCUSSION TOPICS LISTED IN THE NOTICE

- D.1. Completeness:
 - The **Department recommends** that future GETs Reports include working papers that include derivations of all calculations as a separate appendix attached to the GETs Report.
 - The **Department requests** MTO provide the workpapers or other information on the payback period of these seven projects that do not yet have payback period determined in their reply comments.
- D.2. Payback Period Calculation:
 - The **Department recommends** the Commission require the MTO to provide any cases where they have paid curtailment payments to generators on transmission lines where they also hold FTRs.
 - The **Department recommends** the Commission order the MTO to calculate the benefits of GET implementation that include the range of outcomes that would result from physical solutions to congestion rather than the outcomes that result from the application of financial instruments.
- D.3. Accounting for Financial Transmission Rights:
 - The **Department recommends** that the Commission order the MTO to include separate reports of both FTRs held by the MTO and FTRs held by all MISO market participants.
- D.4. Payback Period Thresholds:
 - The **Department recommends** the Commission require the MTO put forth cost estimates and schedules for GETS solutions for any constraints that do not currently meet the five-year payback and instead apply a payback period threshold appropriate to that specific technology.

OR

- The **Department recommends** the Commission create payback period thresholds for each specific GET, including, but not limited to, dynamic line rating, power flow control, topology optimization, and advanced reconductoring.

AND

- The **Department recommends** that the Commission order the MTO to provide cost estimates and implementation timelines for solutions using appropriate payback period.
- D.5. Combinations of GETs and Traditional Upgrades:
 - The **Department recommends** that GETs are considered during the construction of transmission lines and any planned outages from MISO's Tranche 1 and Tranche 2.1 LRTP.
 - The **Department recommends** that, where feasible and where costs would not significantly increase, the MTO consider adding GETs to any proposed traditional upgrades.
 - The **Department recommends** the Commission order that ARR are ineligible to be included for in implementation plans for future GET reports.
- D.6. New or Emerging GETs:
 - The **Department recommends** that future GETs Reports include a section that discusses new or emerging GETs and the possibility of developing GET pilot projects.

ATTACHMENTS

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

**Minnesota Department of Commerce
Public Comments**

Docket No. E999/M-25-99

Dated this 2nd day of **February 2026**

/s/Sharon Ferguson

#	First Name	Last Name	Email	Organization	Agency	Address	Delivery Method	Alternate Delivery Method	View Trade Secret	Service List Name
1	Sasha	Bergman	sasha.bergman@state.mn.us		Public Utilities Commission	121 7th Pl E Ste 350 St. Paul MN, 55101 United States	Electronic Service		Yes	Official 25-99
2	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
3	Mike	Bull	mike.bull@state.mn.us		Public Utilities Commission	121 7th Place East, Suite 350 St. Paul MN, 55101 United States	Electronic Service		Yes	Official 25-99
4	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
5	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
6	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
7	Christine	Marquis	regulatory.records@xcelenergy.com	Xcel Energy		414 Nicollet Mall MN1180-07-MCA Minneapolis MN, 55401 United States	Electronic Service		No	Official 25-99
8	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
9	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
10	Julia	Selker	jselker@gridstrategiesllc.com		WATT Coalition	110 Allen St Suite A&B Cumming GA, 30040 United States	Electronic Service		No	Official 25-99
11	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