MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**May 28, 2026**		**Agenda Item 4****
Company	Minnesota Transmission Owners		
Docket No.	E999/M-25-99		
	In the Matter of the 2025 Minnesota Biennial Transmission Projects Report		
	RE: 2025 Grid Enhancing Technologies Report		
Issues	Should the Commission accept Minnesota Transmission Owners' (MTO's) 2025 Grid Enhancing Technologies (GETs) Report?		
	Should the Commission approve, reject, or modify MTO's 2025 GETs implementation plan?		
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✓ **Relevant Documents**	**Date**
Commission Order and Initial Filing	
Commission Order Establishing Requirements	September 10, 2025
Minnesota Transmission Owners, 2025 Biennial Transmission Projects Report	October 31, 2025
Minnesota Transmission Owners, Appendix B, Grid Enhancing Technologies Study Report	October 31, 2025
Appendix C_Xcel Energy Nobles Battery Study 2025 and Appendix D_System Impact Study Project Nobles BESS	October 31, 2025

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The attached materials are work papers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

✓ **Relevant Documents**	**Date**
Completeness Comments	
Department of Commerce, Division of Energy Resources (DOC), Comments on Completeness	November 19, 2025
WATT Coalition, 2025 Grid Enhancing Technologies Report Completeness Comments	November 20, 2025
Initial Comments	
DOC, Comments	February 2, 2026
WATT Coalition, Public Comment	February 2, 2026
Reply Comments	
Rural Minnesota Energy Board, Reply Comments	February 27, 2026
AMP Coalition, Reply Comments	March 2, 2026
Clean Grid Alliance on behalf of Clean Energy Organizations, Reply Comments (Corrected)	March 2, 2026
MTO, Reply Comments on GETs Report	March 2, 2026
WATT Coalition, Reply Comments on GETs Report	March 2, 2026
Supplemental Comments	
DOC, Supplemental Comments	April 2, 2026
MTO, Supplemental Comments on GETs Report	April 2, 2026
Information Requests	
Minnesota Transmission Owners Response to Request for Information	January 16, 2026
Minnesota Transmission Owners Response to PUC IRs 4-5	April 3, 2026
Minnesota Transmission Owners Response to PUC IRs 6-9	April 7, 2026

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ACRONYMS

AAR: Ambient Adjusted Ratings
ANOPR: Advanced Notice of Proposed Rulemaking
APFC: Advanced Power Flow Control
APC: Adjusted Production Cost
ARR: Auction Revenue Rights
ATT: Advanced Transmission Technology
BESS: Battery Energy Storage System
CRR: Congestion Revenue Rights
DOC: Department of Commerce
DOE: U.S. Department of Energy
DLR: Dynamic Line Rating
DTR: Dynamic Transformer Rating
FERC: Federal Energy Regulatory Commission
FTR: Financial Transmission Rights
GETs: Grid Enhancing Technologies
GNP: Grid North Partners
GRE: Great River Energy
HPC: High Performance Conductor
IOU: Investor-Owned Utility
IPP: Independent Power Producer
INL: Idaho National Laboratory
ISO: Independent System Operator
LRTP: Long Range Transmission Planning
LRZ: Local Resource Zone
MCC: Marginal Congestion Component
MISO: Midcontinent Independent System Operator
MRES: Missouri Rivier Energy Services
MTEP: MISO Transmission Expansion Plan
MTO: Minnesota Transmission Owners
NSP: Northern States Power Company (Xcel)
OTP: Otter Tail Power Company
PFC: Power Flow Control
PPA: Power Purchase Agreement
RTO: Regional Transmission Organization
SMMPA: Southern Minnesota Municipal Power Agency
TO: Topology Optimization
TTO: Transmission Topology Optimization
WATT: Working For Advanced Transmission Technologies Coalition

STATEMENT OF THE ISSUES

The primary issues before the Commission related to the 2025 Grid Enhancing Technologies Report are:

1. Should the Commission accept Minnesota Transmission Owners' (MTO's) 2025 Grid Enhancing Technologies (GETs) Report?
2. Should the Commission approve, reject, or modify MTO's 2025 GETs implementation plan?
3. Should the Commission require future GETs Reports, and if so, what procedural and reporting requirements should be established?

BACKGROUND

I. Relevant Statute, Rules, and Prior Orders

A. Statutory Framework

Under Minn. Stat. § 216B.2425, utilities and companies that own or operate electric transmission lines in Minnesota (Minnesota Transmission Owners, or MTO) are required to file biennial transmission project reports (BTPR), which must identify transmission system inadequacies and solutions to them.[1] The BTPR is filed November 1 of each odd-numbered year.

In 2024, the Minnesota Legislature amended this section to require that going forward, transmission owners will consider grid enhancing technologies (GETs) among the alternatives for addressing transmission system inadequacies identified in their BTPR.[2] Additionally, the Minnesota Legislature passed a 2024 Session Law requiring that certain transmission providers in the state perform additional evaluations of GETs and file a 2025 GETs Report as part of the 2025 BTPR.[3] Staff refers to this Session Law as the "2024 GETs Law" throughout the remainder of these Briefing Papers.

In brief, the 2024 GETs Law requires that an entity owning more than 750 miles of transmission lines in Minnesota identify in its 2025 BTPR locations on its system experiencing or likely to experience high levels of congestion, estimate the costs of this congestion to ratepayers, and evaluate both the technical feasibility and cost-effectiveness of GETs to address each identified instance of grid congestion. These transmission owners must also propose an implementation plan for installing each GET solution that is found to be cost-effective using a methodology

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[1] Minn. Stat. §216B.2425, Subd. 2

[2] Minnesota 2024 Session Laws, Chapter 127, Article 42, Sections 19, 20 and 21. Available at: https://www.revisor.mn.gov/laws/2024/0/Session+Law/Chapter/127/

[3] Minnesota Session Laws, 2024, Chapter 127, Article 42, Section 52, Available at: https://www.revisor.mn.gov/laws/2024/0/Session+Law/Chapter/127/

established by the Commission.

The Commission is responsible for reviewing the GETs implementation plan, and may approve, reject, or modify it. If the Commission approves a GETs implementation plan, each public utility must file a workplan, cost estimate, and schedule for installation of approved elements in their service areas within 90 days of the Commission Order. The Commission's Order is advisory for MTOs that are not public utilities under Minnesota law.

The 2024 GETs Law is included in full below.

> **Sec. 52. GRID ENHANCING TECHNOLOGIES REPORT; PUBLIC UTILITIES COMMISSION ORDER.**
> **Subdivision 1. Definitions.** (a) For the purposes of this section, the following terms have the meanings given.
> (b) "Capacity" means the maximum amount of electricity that can flow through a transmission line while observing industry safety standards.
> (c) "Congestion" means a condition in which a lack of transmission line capacity prevents the delivery of the lowest-cost electricity dispatched to meet load at a specific location.
> (d) "Dynamic line rating" means hardware or software used to calculate the thermal limit of existing transmission lines at a specific point in time by incorporating information on real-time and forecasted weather conditions.
> (e) "Grid enhancing technology" means hardware or software that reduces congestion or enhances the flexibility of the transmission system by increasing the capacity of a high-voltage transmission line or rerouting electricity from overloaded to uncongested lines, while maintaining industry safety standards. Grid enhancing technologies include but are not limited to dynamic line rating, advanced power flow controllers, and topology optimization.
> (f) "Line rating methodology" means a methodology used to calculate the maximum amount of electricity that can be carried by a transmission line without exceeding thermal limits designed to ensure safety.
> (g) "Power flow controller" means hardware and software used to reroute electricity from overloaded transmission lines to underutilized transmission lines.
> (h) "Thermal limit" means the temperature a transmission line reaches when heat from the electric current flow within the transmission line causes excessive sagging of the transmission line.
> (i) "Topology optimization" means a software technology that uses mathematical models to identify reconfigurations in the transmission grid in order to reroute electricity from overloaded transmission lines to underutilized transmission lines.
> (j) "Transmission line" has the meaning given to "high-voltage transmission line" in section 216E.01. subdivision 4.
> (k) "Transmission system" means a network of high-voltage transmission lines owned or operated by an entity subject to this section that transports electricity to Minnesota customers.
> **Subd. 2. Report; content.** An entity that owns more than 750 miles of transmission lines in Minnesota, as reported in the state transmission report submitted to the Public Utilities Commission under Minnesota Statutes, section

216B.2425, by November 1, 2025, must include in that report information that:
(1) identifies, during each of the last three years, locations that experienced 168 hours or more of congestion, or the ten locations at which the most costly congestion occurred, whichever measure produces the greater number of locations;
(2) estimates the frequency of congestion at each location and the increased cost to ratepayers resulting from the substitution of higher-priced electricity;
(3) identifies locations on each transmission system that are likely to experience high levels of congestion during the next five years;
(4) evaluates the technical feasibility and estimates the cost of installing one or more grid enhancing technologies to address each instance of grid congestion identified in clause (1), and projects the grid enhancing technology's efficacy in reducing congestion;
(5) analyzes the cost-effectiveness of installing grid enhancing technologies to address each instance of congestion identified in clause (1) by using the information developed in clause (2) to calculate the payback period of each installation, using a methodology developed by the commission;
(6) proposes an implementation plan, including a schedule and cost estimate, to install grid enhancing technologies at each congestion point identified in clause (1) at which the payback period is less than or equal to a value determined by the commission, in order to maximize transmission system capacity; and
(7) explains the transmission owner's current line rating methodology.
Subd. 3. Commission review; order. (a) The commission must review the implementation plans proposed by each reporting entity as required in subdivision 2, clause (6), and must:
(1) review, and may approve, reject, or modify, the plan; and
(2) issue an order requiring implementation of an approved plan.
(b) Within 90 days of the date the commission issues an order under this subdivision each public utility must file with the commission a plan containing a workplan, cost estimate, and schedule to implement the elements of the plan approved by the commission that are located within the public utility's electric service area. For each entity required to report under this section that is not a public utility, the commission's order is advisory.
Subd. 4.Cost recovery. Notwithstanding any other provision of this chapter, the commission may approve cost recovery under Minnesota Statutes, section 216B.16, including an appropriate rate of return, of any prudent and reasonable investments made or expenses incurred by a public utility to administer and implement a grid enhancing technologies plan approved by the commission under this section.
EFFECTIVE DATE. This section is effective the day following final enactment.

B. 2024 Biennial Transmission Projects Report Order

In the Commission's June 27, 2024 *Order Accepting Report* in Docket No. E999/M-23-91 (the 2023 Biennial Transmission Projects Report), the Commission ordered MTO to include the following additional information in their 2025 BTPR:

A. An update on the progress and/or performance of the Grid North Partners' proposal for nineteen transmission upgrade projects aimed at enhancing reliability and easing congestion in Minnesota.
B. Information about short-term solutions to increase the robustness of the transmission system they have deployed or plan on deploying along with a report on their performance such as:
    1. dynamic line ratings,
    2. transmission system optimization and reconfigurations,
    3. adjusting transmission conductor limitations to increase line ratings,
    4. increasing substation limiter sizes, and
    5. other grid enhancing technologies that they have deployed or plan on deploying.[4]

A description of progress on the Grid North Partners congestion relief portfolio was included in the 2025 BTPR, Section 9.3 and 2025 GETs Report, page 12. Information about GETs and transmission owners' efforts to deploy technology solutions is provided in the 2025 GETs Report, pages 7-8, 12, and 15-16. The information provided by MTOs is described in Section VI of these briefing papers.

C. 2025 GETs Order

As noted earlier, the 2024 GETs Law requires the Commission to establish methodology by which transmission owners will calculate the payback period of each GETs solution being studied, and a payback period threshold for determining which GETs solutions are included in the GETs Implementation Plan. The Commission requested comments on these topics in 2025 and issued an order on September 10, 2025 ("2025 GETs Order") directing transmission owners to complete the following requirements for the 2025 GETs Report. Staff has summarized the ordering paragraphs below for brevity.

1. Calculate a payback period for each potential GET deployment comparing project costs to average annual savings;

2. Explain each cost and benefit factor used in the payback period calculation and provide work papers showing their calculations;

3. Calculate the cost of historical congestion by netting revenue from auction revenue rights/financial transmission rights from the congestion charge of the constraint;

4. Include in the 2025 GETs Report information on several topics, including:
    a. Whether congestion is expected to continue at each high-congestion location;
    b. An implementation plan for GETs deployments with a payback period of 5 years

[4] *In the Matter of the 2023 Minnesota Biennial Transmission Projects Report, Commission Order Accepting Report,* June 27, 2024, Docket No. E999/M-23-91

or less;
c. An implementation plan for GETs deployments meeting a payback period threshold appropriate to the specific application;
d. An explanation of payback period thresholds used in the implementation plan;
e. Efforts to compare GETs with traditional solutions and combinations thereof;
f. Whether and how equity, environmental justice, and workforce impacts were incorporated into the GETs analysis;
g. Collaboration with MISO and other transmission owners to reduce congestion and optimize transmission investments through regional processes;
h. Consultation with grid enhancing technology vendors and other stakeholders;

5. Share underlying assumptions used in the GETs analysis to the extent possible.[5]

D. 2025 Nobles County Curtailment Order

In the Commission's March 2025 Order in Docket No. E999/CI-24-316, an investigation into solutions to curtailment at the Nobles County Substation, the Commission ordered transmission owners to include a "cost-benefit analysis in their Biennial Transmission Projects Report that compares any feasible battery storage solution to status quo conditions and to its performance under planned upgrades at the Nobles County substation area."[6]

Xcel Energy's economic analysis of a battery energy storage system (BESS) at the Nobles County Substation is included as Appendix C and Xcel's System Impact Study for the Nobles BESS is included as Appendix D of the BTPR. The economic analysis evaluated data from 2024 through the first half of 2025 and concluded that a 300 MW, 4-hour battery would have helped reduce curtailment in the region.[7] For example, when Xcel assumed the BESS only charged when at least one of the most-curtailed Xcel wind projects was bring curtailed, and the BESS discharged when LMP was at or above $5/MWh, Xcel estimated it would have reduced curtailment by 240,257 MWh, or 22%, in 2024.

Xcel requested Commission approval of the 300 MW Nobles BESS in Docket No. E002/RP-24-67 in February 2026.[8] Xcel also applied for Expedited Resource Addition Study (ERAS) with the Midcontinent Independent System Operator, Inc. (MISO). The project will be included in MISO ERAS Cycle 3.[9]

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[5] *In the Matter of the 2025 Biennial Transmission Projects Report, Order Establishing Requirements,* September 10, 2025, Docket No. E999/M-25-99. Ordering Paragraphs 1-6. ("2025 GETs Order")

[6] *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.

[7] Nobles BESS Study (BTPR Appendix C) at 2

[8] *In the Matter of Xcel Energy's Petition for Approval of Generator Projects for MISO's Expedited Resource Addition Study (ERAS),* Xcel Energy, Petition, February 20, 2026, Docket No. E002/RP-24-67

[9] See MISO ERAS Interconnection Requests. (Accessed April 27, 2026)

II. Minnesota Transmission Owners

Since enactment of biennial transmission plan requirements (Minn. Stat. § 216B.2425) in 2001, affected transmission owners have typically collaborated to submit one BTPR as the Minnesota Transmission Owners (MTO), a group now comprised of 14 investor-owned, municipal and cooperative utilities.[10] The requirements of the 2024 GETs Law apply to entities that own more than 750 miles of transmission in Minnesota, which is a subset of the 14 MTO members.

Table 1: Minnesota Transmission Owners and GETs Requirements

Transmission Owner Name	Participated in GETs Report	Subject to 2024 GETs Law	MN Public Utility
Minnesota Power (MP)	X	X	X
Otter Tail Power Company (OTP)	X	X	X
Xcel Energy (Xcel)	X	X	X
Great River Energy (GRE)	X	X	
ITC Midwest (ITCM)	X	X	
Missouri River Energy Services (MRES)	X		
Southern Minnesota Municipal Power Agency (SMMPA)	X		
Minnkota Power Cooperative	X		
American Transmission Company			
Central Minnesota Municipal Power Agency			
Dairyland Power Cooperative			
East River Electric Power Cooperative			
L&O Power Cooperative			
Rochester Public Utilities			
Total: 14 MTO Members	**8**	**5**	**3**

Note that MTO has a different, though overlapping, membership than Grid North Partners. Grid North Partners is a group of 10 utilities (including investor-owned, cooperative and municipal utilities) that work together on transmission projects in Minnesota and surrounding states. It includes many of the utilities shown in Table 1, as well as WPPI Energy in Wisconsin, but does not include transmission-only providers.[11]

III. Grid Enhancing Technologies

The 2024 GETs Law provides three examples of technologies that qualify as GETs: dynamic line rating, advanced power flow controllers, and topology optimization. To aid the Commission in

[10] MTO Comments, Docket No. E999/TL-01-961, July 30, 2001, at 1

[11] See About Us - Grid North Partners (Accessed April 27, 2026)

its decision-making process, Staff provides a brief summary of how each of these technologies works, as well as three related technologies that are discussed in this record – ambient adjusted ratings (AAR), dynamic transformer ratings (DTR), and high-performance conductor (or advanced conductor) (HPC). Staff notes this is *not* a comprehensive list of technologies that could qualify as GETs.

The following definitions are from the Idaho National Laboratory, which is a national hub for the study and testing of GETs:[12]

Ambient Adjusted Ratings (AAR): Using hourly ambient temperature and the impact of daytime versus nighttime solar heating along a line (conductor) to determine transmission line capacity. This is often greater than the static rating normally assigned to a transmission line.

Dynamic Line Rating (DLR): Using weather conditions such as wind speed, direction, ambient air temperature, or other measurements to determine the true temperature of a conductor and consequently the maximum power that can safely flow on a transmission line at a given time. This is often greater than the static rating normally assigned to a transmission line.

Dynamic Transformer Rating (DTR): Using weather conditions such as wind speed, direction, ambient air temperature, or other measurements to determine the true temperature of a transformer and consequently the maximum power that can safely flow through the device at a given time. (Comparable to DLR, but for transformers).

Advanced Power Flow Controller (APFC or PFC): A device which actively manages power flows by changing the reactance in the lines. This is useful for redistributing power flow in a mesh network to relieve congestion.

High Performance Conductor (HPC): Also called Advanced Conductors, HPCs refer to a range of conductor technologies that use stronger and more heat-dissipating or heat-tolerant materials and composite core designs which make them capable of carrying more power with less sag.

Topology Optimization (TO): Also called Transmission Topology Optimization (TTO), this is the use of software to reconfigure topology of a network to mitigate congestion, improve transmission capacity, and add flexibility.

Several parties provided references to case studies of GETs deployments in the Midwest, other regions of the U.S., and in other countries.

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[12] Idaho National Laboratory, *Transmission Optimization with Grid-Enhancing Technologies Overview,* at 2, available at https://inl.gov/content/uploads/2023/07/Transmission-Optimization-with-Grid-Enhancing-Technologies.pdf and *Grid Enhancing Technologies*, November 2024, at 2, available at https://inl.gov/content/uploads/2024/03/POWER_Grid-Enhancing-Technologies.pdf

IV. Related Federal Regulatory and Funding Actions

There are at least two recent regulatory actions by the Federal Energy Regulatory Commission (FERC) that will affect transmission owners' implementation of GETs in coming years, and one new funding opportunity from the Department of Energy (DOE) that transmission owners may be able to take advantage of to support GETs implementation.

Order 881: Requiring Ambient Adjusted Ratings

On December 16, 2021, FERC issued a final Order (Order 881) requiring implementation of AAR by public utilities, RTOs and ISOs to improve the accuracy and transparency of electric transmission line ratings.[13] MISO submitted proposed tariff revisions to FERC to comply with this order in July 2022, requesting an effective date in July 2025. Then, in early 2025, MISO requested and was granted a three-year extension for implementation until December 31, 2028.

ANOPR on Dynamic Line Ratings

On June 27, 2024, FERC issued an Advanced Notice of Proposed Rulemaking (ANOPR) in Docket No. RM24-6-000, in which it solicited comments on:

> Potential reforms to implement dynamic line ratings and, thereby, improve the accuracy of transmission line ratings. These potential reforms would require transmission line ratings to reflect solar heating based on the sun's position and forecastable cloud cover and require transmission line ratings to reflect forecasts of wind conditions on certain transmission lines. The potential reforms would also ensure transparency in the development and implementation of dynamic line ratings and enhance data reporting practices related to congestion in non-regional transmission organization/independent system operator regions to identify candidate transmission lines for the requirement to reflect forecasts of wind conditions.[14]

The comment period on this ANOPR closed in late 2024, and FERC has not yet published information about intended next steps.

DOE SPARK Funding Opportunity

On March 12, 2026, the U.S. DOE Office of Electricity announced an approximately $1.9 billion funding opportunity to catalyze electricity infrastructure investments to meet electricity demand growth and resource adequacy requirements. The program, named Speed to Power through Accelerated Reconductoring and other Key Advanced Transmission Technology Upgrades (SPARK) is an outgrowth of the Grid Resilience and Innovation Partnerships (GRIP) Program that was authorized under the Infrastructure Investment and Jobs Act enacted in

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[13] FERC Order 881, December 16, 2021, FERC Docket No. RM20-16, available at: https://www.ferc.gov/media/e-1-rm20-16-000

[14] FERC ANOPR, June 27, 2024, FERC Docket No. RM24-6-000, p 1, available here: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240627-31062

2021. The SPARK program emphasizes investment in reconductoring and other advanced transmission technologies.

PUC Staff requested information from MTO members on whether any intend to submit applications to the SPARK program in PUC IR 5. Concept papers were due to DOE by April 2, 2026. Note that for at least one of the three topic areas (Grid Resilience), projects must be supplemental to existing or planned projects, so the funding may not directly offset planned investments.[15] Three Minnesota transmission owners indicated plans to pursue SPARK funding: GRE and Xcel indicated they would apply for a system-wide portfolio of ATTs, Otter Tail indicated it is working with a university on a SPARK smart grid partnership. Dairyland and Minnkota indicated they may apply as part of a consortium. ATC and ITC indicated they may apply but such projects would be outside of Minnesota.[16]

V. Procedural Timeline

On September 10, 2025 the Commission issued its Order Establishing Requirements for the 2025 Grid Enhancing Technologies (GETs) Report, including the payback period methodology and threshold to be used in developing the 2025 GETs Report.

On October 31, 2025, Minnesota Transmission Owners (MTO) filed the 2025 Biennial Transmission Projects Report (BTPR), including the 2025 GETs Report as Appendix B.

On November 10, 2025, MTO requested the Commission vary its rules (in Minn. R. 7848.1800) for comment periods in this docket, and proposed a separate schedule for comments on the 2025 GETs Report.

By November 20, 2025, the Commission received Comments regarding Completeness of the 2025 GETs Report from the Department of Commerce, Division of Energy Resources (DOC DER) and WATT Coalition. The Department recommended that the Commission approve the MTO's requested variance of comment periods on the GETs Report.

On November 26, 2025, the Commission issued an Order approving MTO's requested variance of comment periods on the GETs Report.

By February 2, 2026, the Commission received Initial Comments on the 2025 GETs Report from DOC DER and WATT Coalition.

By March 2, 2026, the Commission received Reply Comments on the 2025 GETs Report from the AMP Coalition, Clean Energy Organizations (CEOs), MTO, Minnesota Rural Energy Board

[15] US DOE, *SPARK Funding Opportunity Concept Paper Feedback webinar slides*, accessed May 5, 2026, available here: https://www.energy.gov/documents/spark-concept-paper-feedback-webinar-slides

[16] MTO Response to PUC IR 5

(MREB), and WATT Coalition.

By April 2, 2026, the Commission received Supplemental Comments from DOC DER and MTO.

A. Commenting Organizations

Several of the organizations that filed comments in this docket are not regular commenters in Minnesota Public Utilities Commission dockets. To introduce these organizations and provide context for their comments, Staff includes a brief description of each party at the beginning of the relevant Party Position Discussion section.

AMP Coalition
The AMP Coalition is an ad hoc coalition of High Performance Conductor (HPC) technology vendors. AMP's goal is to further the use of HPCs as a tool for modernizing and increasing grid capacity, as well as improving the overall resilience, reliability, and energy efficiency of the grid. The coalition includes vendors of both carbon core conductors and superconductors, the two primary HPC technology types.

Clean Energy Organizations (CEOs)
Clean Grid Alliance, Fresh Energy, Sierra Club, and Minnesota Center for Environmental Advocacy submitted joint comments as the CEOs. The four nonprofit organizations regularly participate in resource planning and acquisition matters before the Commission, advocating for resource choices that minimize or reduce pollutant emissions, advance renewable energy, and focus on equitable outcomes.

Minnesota Department of Commerce Division of Energy Resources (DOC)
The Department is an intervening party by right in all Commission proceedings. The Division of Energy Resources has several roles, including advocating for a reliable, low-cost energy system that minimizes risks for Minnesota's utility consumers and the environment now and into the future.

Rural Minnesota Energy Board (RMEB)
RMEB is a joint powers board of 18 counties in southern Minnesota. The board was formed to provide policy guidance on issues surrounding energy development in rural Minnesota. Originally formed in 1996 as the Ridge Counties Task Force, it evolved into the Wind Task Force, the SW Minnesota Energy Task Force, and the Rural Minnesota Energy Task Force as both membership and policy issues expanded. Its initial focus on wind energy has broadened to include renewable energy and transmission issues.

WATT Coalition
The Working for Advanced Transmission Technologies (WATT) Coalition advocates for policy that supports the wide deployment of GETs to accelerate lower energy costs and enable economic growth. WATT's membership includes Dynamic Line Rating (DLR), Advanced Power Flow Control (APFC), and Transmission Topology Optimization (TTO) vendors, as well as

independent power producers, investors, and utilities.

SUMMARY OF THE 2025 GETS REPORT

VI. Overview of Identified Constraints and GETs Solutions

The 2024 GETs Law requires that transmission owners identity, "during each of the last three years, locations that experienced 168 hours or more of congestion, or the ten locations at which the most costly congestion occurred, whichever measure produces the greater number of locations."[17] Using congestion data for the years 2022 – 2024 from MISO Day-Ahead reports,[18] MTO identified **66 constraints** in Minnesota that had more than 168 hours of congestion in at least one of the three prior years. In the remainder of these briefing papers, Staff refer to these 66 locations as "high-congestion constraints".

For each of the 66 constraints, MTO studied potential GETs and traditional solutions, and identified **12 constraints** where a solution met the 5-year payback period threshold established in the Commission's 2025 GETs Order. MTO submitted implementation plans for these 12 projects.

Under the 2024 GETs Law, the Commission "must review, and may approve, reject, or modify" GETs implementation plans, and "must and issue an order requiring implementation of an approved plan."[19] Therefore these 12 projects *require* Commission review and action, though of course the Commission may review and take action on the full contents of the GETs Report as appropriate.

MTO grouped the 66 high-congestion constraints into seven categories:

- 12 constraints with solutions (either GETs, traditional, or a combination) that met the relevant payback period threshold (i.e., 5 years).
- 7 constraints had solutions where MTO needs to do further analysis to determine if the payback period threshold is met.
- 2 constraints had no solutions identified.
- 2 constraints had solutions identified but did *not* meet the payback period threshold.
- 18 constraints have had projects completed within the past three years, or have planned upgrades that are part of a MISO Transmission Expansion Plan (MTEP) process.
- 17 constraints are or were caused by temporary outages or operating conditions. Due to the temporary nature of these conditions, MTO did not identify solutions

[17] 2024 GETs Law, Subd. 2(1)

[18] See: MISO Market Reports

[19] 2024 GETs Law, Subd. 3

for these.

- 8 constraints were identified as having high congestion in future models. MTO did not develop solutions for these but indicated that it would continue to monitor them for potential future GETs implementation.

For each of the 66 identified constraints, MTO provided constraint details which were marked as Trade Secret. The type of information provided for each constraint included:

- Name of constraint
- Facility ownership for lines and terminals
- Details on the top three limiting elements in both summer and winter
- Congestion statistics including hours, shadow price and congestion charge for three historical and two modeled future years
- A description of historical congestion causes
- A graph of congestion occurrences over the three-year historical period
- A map showing LMPs during an example congestion period
- Details on proposed GETs and traditional solutions
- Payback Period details for the potential solutions
- Description of anticipated future congestion, if any

Staff provides more detail on the 12 GETs Implementation Plan projects in Section VIII.

Regarding compliance with the Commission's 2024 Order accepting the prior BTPR, MTO provided a high-level explanation of several grid enhancing technologies that can enable increases in transmission equipment ratings, members' work to deploy GETs, and the Grid North Partners near-term congestion portfolio.

MTO noted that the GETs Report addresses 30 total GETs solutions that are being developed to address congestion in the near term. 12 of these are new projects developed through analysis for the 2025 GETs Report and included in the GETs Implementation Plan; the remaining 18 are projects that had been identified through Grid North Partners' 2023 congestion study and have recently gone into service or are under construction.[20] MTO provided an update on the Grid North Partners projects, as required by the Commission's Order Accepting the 2023 BTPR. Of the 18 projects listed, two are still in progress, two have been cancelled or put on hold due to increases in costs, and 14 are already in service.[21]

MTO estimated the Grid North Partners portfolio will cost $130 million. MTO asserts that this package of project comprises "low hanging fruit" opportunities for congestion alleviation and that remaining constraints may not be as straightforward or cost-effective to

[20] BTPR Section 9.3, p. 244-245

[21] *Ibid.*

resolve even when using GETs.[22] MTO noted that some GETs projects may require traditional upgrades (such as terminal equipment) in order to realize any benefit and in some cases, the terminal equipment is the limiting factor and replacement of that equipment may be the best solution. MTO also pointed out that at times, addressing congestion at one facility causes it to shift to adjacent facilities, making it necessary to study a broader scope than just the constrained facility.[23]

VII. Calculating the Cost of Congestion

A. Congestion Charge

As approved in the Commission's 2025 GETs Order, MTO used the "congestion charge" of each high-congestion constraint to approximate the cost of congestion (or the value of avoiding congestion) at that location, and subtracted Financial Transmission Right (FTR) profits to arrive at a final value for each constraint.

To perform this calculation MTO start by finding the "shadow price" of each constraint. A shadow price is the incremental cost saving associated with relieving a binding constraint by 1MW, resulting in a dollar-per-MW value. Shadow price is a metric reported by PROMOD (an electric market simulation model, which incorporates grid topology) and is commonly used by transmission owners to assess the severity of different constraints. Then, the congestion charge is calculated by multiplying the shadow price of a constraint ($/MW), by the full rating of the constraint (MW), resulting in a dollar value.[24]

As noted in earlier rounds of comments in this docket, congestion charge very likely overstates the value of avoided congestion because it assigns the shadow price to the *full rating* of the equipment.[25] In reality, the solution may not always be able to eliminate congestion up to the full equipment rating and/or there may be secondary limiting elements that continue to cause a constraint below the full rating. However, congestion charge has the benefits of being relatively straightforward to calculate while approximating the aggregate value of relieving a constraint.

B. Methodology for Netting FTRs

1. Overview

As required by the 2025 GETs Order, MTO accounted for Financial Transmission Right (FTR) profits in the calculation of a constraint's congestion charge.[26]

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[22] GETs Report Comments at 12

[23] *Ibid*.

[24] 2025 GETs Order, at 3

[25] MTO Initial Comments, April 11, 2025, Docket No. E999/M-25-99, at 6

[26] 2025 GETs Order, Ordering Paragraph 3

> FTRs are used in the MISO market to allow a holder to hedge against congestion costs in the day ahead energy markets. An FTR is defined from a source node to a sink node for a specified MW value. When congestion occurs in the day-ahead market for a given hour, the FTR holder is either paid or must pay a fraction of the overall congestion charge for that hour depending on the direction of the congestion relative to the FTR source and sink.
> …
> FTRs are defined from a source node to a sink node, and these nodes may be on each side of the constraints or even the same side of the constraint. Taking the FTR profits, which are determined by the entire market conditions, for a given hour and assigning a portion of the profit to individual constraints is a complicated process and thus an approximation technique was used in this report. To approximate the FTR adjustments, an approach based on a method for "Allocating CRR Revenue Inadequacy by Constraint to CRR Holders" described in a whitepaper by the California ISO Department of Market Monitoring in 2014 was used.[27]

MTO provided the following equation used to apply a fraction of annual FTR profit to an individual constraint:

$$Profit\ Share_n^{FTR,m} = Total\ Profit^{FTR,m} * |(SF^{src,m} - SF_n^{snk,m})|$$

Where:

- Profit Share$_n^{FTR,m}$ is the share of profit from FTR *m* applicable to constraint *n*
- Total Profit^{FTR,m} is the annual profit of FTR *m*
- SF^{src,m} is the shift factor at the source
- SF^{snk,m} is the shift factor at the sink

The equation states that the share of profit from FTR *m* applicable to a specific constraint *n* can be found by multiplying the annual profit of FTR *m* by the "shift factor" difference between the FTR's source and sink relative to constraint *n*.

> Shift factors (also known as distribution factors) measure the percentage of flow that would occur on a line after injecting one MW at the associated node. Every branch has a unique shift factor associated with every single node. The difference between source and sink shift factor of an FTR provides a percentage of flow expected on a specific branch resulting from transfers between that FTR's source and sink. Multiplying

[27] See: California ISO, Allocating CRR Revenue Inadequacy by Constraint to CRR Holders (Accessed April 28, 2026)

> this percentage by the FTR's total profit results in a portion of the FTR's profit being associated with constraint *n*. Shift factors are completely dependent on the transmission topology and the amount of load or generation at the location is irrelevant. The absolute value of the shift factor is taken so that the sign of the profit share is dependent entirely on whether the profit was positive or negative.[28]

Market participants typically have multiple FTRs active at once, so to find the total FTR profits associated with a constraint, MTO summed the constraint's profit share of each FTR. Thus, the overall equation used to find the FTR adjustment for each constraint is:

$$FTR\ Adjustment_n = \sum_{m=1}^{F} Profit^{FTR,m} * |(SF_n^{src,m} - SF_n^{snk,m})|$$

For each constraint, MTO added the FTR adjustment and the original congestion charge to find the final value used in the GETs Report payback period calculation. MTO noted that FTR profits may be positive or negative, so the overall adjustment may either increase or decrease the final congestion charge. Most congestion charges are costing the system (i.e., are negative) and in those cases, FTRs that are profitable (i.e., positive) will reduce the congestion charge. However, MTO pointed out that there are certain years and constraints where the FTR profit assigned to a constraint is *greater* than its original congestion charge, which makes the final congestion charge appear positive, implying that this is a net positive for the system. In these cases, MTO instead set the final congestion charge to zero, implying that the FTR hedge completely covered the congestion for that year.[29]

MTO provided the following hypothetical example of a constraint where FTR profits exceeded congestion charge, leading to a final congestion charge value of zero:

- If a constraint in 2022 had a congestion charge of ($100,000) and,
- The total FTR adjustment share for this constraint in 2022 was $150,000 then,
- The congestion charge for the constraint in 2022 is reported as $0 and not $50,000.

2. Potential Deficiencies in FTR Allocation Method

MTO based the FTR netting method used in the GETs Report on similar methods used in other regions in the United States. Nonetheless, MTO acknowledged this was its first attempt to adjust congestion costs by FTR profits, and it is aware of some deficiencies with the method.

1. <u>FTRs Across the Entire MISO Footprint Impact Congestion:</u> MTO clarified that for the GETs Report, FTRs from GRE, MP, MRES, OTP, and Xcel were accounted for in making congestion charge adjustments. However, participants across MISO participate in the

[28] 2025 GETs Report, at 9

[29] 2025 GETs Report, at 10-11

FTR market and these hedges could impact the final congestion charge, though it is not possible to collect FTR information from all market participants for all constraints.

2. Shift Factors and Congestion are Topology Dependent: MTO noted that it derived shift factors for this calculation from a PROMOD simulation that approximated 2025 grid topology conditions with no outages. Of course, actual congestion and FTR revenues depend on real-time conditions of the transmission system, and therefore will differ from the PROMOD results. To perfectly calculate a congestion charge adjustment, one would use hourly shift factors based on historical system conditions; however, MTO stated that getting this hourly information is not feasible.

3. Shift Factor Information is Based on Individual Buses while FTRs May Be Based on Aggregate Hubs: For an FTR, the source and sink nodes may be pricing nodes that are aggregates of many different system buses over a wide geographic and electrical area (for example, the MINN.HUB). However, shift factors are calculated based on a single bus. For FTRs related to aggregate pricing nodes, MTO calculated peak load weighted average shift factors—with peak load values taken from the near-term PROMOD model—to account for the broader geographic areas involved.

VIII. Detail on GETs Implementation Plan Projects

MTO provided a map of the 12 projects included in its Implementation Plan, meaning the solution met the five-year payback period threshold. The 12 solutions address constraints at multiple voltage levels and are geographically distributed across the state.

[Trade Secret Information Begins]

[Trade Secret Information Ends]

As noted earlier, for each of the 66 high-congestion constraints evaluated, MTO provided an overview of information on the constraint, historical congestion, and potential solutions. Table 2 below shows the Department's summary of this information for the 12 solutions included in the implementation plan.

Table 2. Constraints with Solution Proposals, Payback Period Met[30]

Project	Transmission Owner	Traditional Solution	GETs Solution	Solution Cost	3-year Avg *Adjusted* Congestion Charge	Payback Period
[Trade Secret Information Begins]						

[30] DOC DER, Initial Comments at 6 (Table 1)

[redacted]

[Trade Secret Information Ends]

Staff provides the following high-level takeaways of these 12 projects:

Project Types:

- Five of the projects are focused on GET deployment.
- One project is a traditional solution to increase headroom and maximize existing DLR.
- Two of the projects are traditional solutions where GETs are being considered for addition at a later date.
- Four of the projects are traditional solutions not connected to GETs deployment.

Payback Periods:

- Overall, payback periods range from 0.1 years to 4.7 years, and the average for the portfolio is 1.3 years.
- Payback periods did not differ substantially between GETs and traditional projects in this portfolio:
    - For GET-only solutions, payback periods range from 0.1 years to 4.5 years, and the average is 1.04 years.
    - For traditional solutions payback periods range from 0.16 years to 3.11 years, and the average is 1.5 years.
    - For combined solutions, payback periods range from 0.0 years to 4.7 years, and the average is 2.35 years.

The projects affect facilities owned by GRE, ITC Midwest, Minnesota Power, MRES, Otter Tail, and Xcel**.** Table 3 summarizes the 12 proposed deployments by ownership. Note that several solutions involve shared infrastructure or locations where, for example, a line may have different ownership from one or more terminals. Therefore the "count of solutions" by owner will exceed 12.

Table 3. PUC Staff Summary of Proposed Solutions by Owner

Transmission Owner	Count of Solutions	Category
GRE	3	2 GETs 1 Combined (traditional in support of DLR)
ITC Midwest	1	1 GETs
Minnesota Power	5	4 GETs 1 Combined (traditional in support of DLR)
MRES	1	1 Traditional (possible to add DLR in future)
Otter Tail	2	2 Traditional (possible to add DLR in future)
Xcel	5	1 GETs 4 Traditional

A. Rate Impact

To help the Commission determine the potential rate and bill impacts of the transmission projects proposed in the 2025 BTPR and GETs Reports, PUC Staff asked MTO and its public utility members several information requests. Staff's questions and MTO responses are summarized below.

Cost recovery mechanisms:

- MTO stated that cost recovery mechanisms will vary by project. The investor-owned utilities expect to use a combination of base rates, transmission riders, and wholesale cost recovery mechanisms, as applicable. Projects that obtain a Certificate of Need may be recovered through transmission riders, unless rate case timing lines up for the project to be included in base rates.
- The IOUs also use wholesale and interjurisdictional cost recovery mechanisms for transmission projects where appropriate.
- Projects that are eligible for regional cost allocation through MISO, including Long-Range Transmission Plan (LRTP), and Market Efficiency Projects (MEP), will be subject to MISO cost recovery mechanisms.[31]

Impact on rates and bills:

- IOUs indicated they had not performed a standalone analysis of the net rate or bill impact of specific transmission investments included in either the BTPR or GETs Report. They noted that estimated cost per project are included in the GETs report and, for BTPR projects, are included when projects are submitted to the MISO database.
- A rate impact assessment is not available for a few reasons: the projects in the BTPR are in varying stages of development (from concept to nearly complete), and will use a variety of cost recovery mechanisms.
- Rate impact analyses will be performed, as appropriate, at the time a utility seeks cost recovery for specific transmission projects in the relevant cost recovery proceedings.[32]

Timing of rate impacts:

- MTO stated customers will generally start to see rate impacts during or shortly after the in-service year for each project.[33]

Minnesota share of MISO-approved projects:

- MTO noted the portion of costs that will be allocated to each utility and recovered from Minnesota customers varies by project and depends on several factors, including the applicable MISO cost allocation methodology, jurisdictional allocation, and the

[31] MTO Response to PUC IR 6

[32] MTO Response to PUC IR 7

[33] MTO Response to PUC IR 8

ownership structure. For many projects, these determinations have not yet been finalized.
- While not available at this time, this information will be developed and provided, as applicable, when a utility seeks cost recovery for specific projects.[34]

B. Staff Analysis

Staff finds that, while MTO's responses reflect the complexity and early-stage development of many proposed projects, providing more proactive rate impact information would better support the Commission's oversight responsibilities and improve transparency for Minnesota ratepayers. Accordingly, the Commission could consider directing IOUs to include preliminary rate impact estimates and Minnesota-specific cost allocation information in GETs Reports, even where those estimates remain subject to change.

Staff notes that the aggregate cost of proposed solutions is **[Trade Secret Information Begins]** [redacted] **[Trade Secret Information Ends]** and the aggregate adjusted congestion charge for the portfolio is **[Trade Secret Information Begins]** [redacted] **[Trade Secret Information Ends]**, and the calculated payback period is 1.3 years on average. While the adjusted congestion charge is not a precise prediction of how much congestion savings customers will see, the results indicate that it is likely this portfolio of investments will deliver net benefits to customers within a relatively short period of time.

DISCUSSION AND PARTY POSITIONS

Overall, commenters appreciated the information provided in the GETs Report and saw significant potential benefits in continuing to systematically evaluate opportunities to reduce congestion and improve Minnesota's transmission system capacity. WATT commended the MTO's approach of submitting a single joint GETs Report, noting that in some other jurisdictions, deployments have not been feasible due to disagreement or lack of coordination between neighboring transmission owners.[35]

Commenters largely agreed in their critiques of the GETs Report and Implementation Plan. Their recommendations generally fell into the following categories:
- Improve transparency of data access and provide more supporting data
- Evaluate a broader range of technology types
- Evaluate a broader range of constraints
- Consider additional benefit factors in the payback period analysis
- Improve the FTR adjustment methodology
- Use technology-specific payback periods

[34] MTO Response to PUC IR 9

[35] WATT Reply Comments at 1

This section of briefing papers is organized by these categories as well. Under each topic, Staff summarizes party comments and provides staff analysis.

IX. Completeness of the 2025 Report and Requirements for Future GETs Reports
X. Technologies for Evaluation in the GETs Report
XI. Constraints to Evaluate in the GETs Report
XII. Payback Period Methodology
XIII. FTR Adjustment Methodology
XIV. Payback Period Threshold

The first section concerns approval of the 2025 GETs Report and Implementation Plan and filing requirements for future reports. If the Commission finds deficiencies with the Report in any area, it can require compliance filings to remedy the deficits. Sections X through XVI largely concern recommended improvements and additional reporting requirements for future GETs Reports.

IX. Completeness of the 2025 Report and Requirements for Future GETs Reports

MTO, WATT, and the Department recommended that Commission find the 2025 GETs Report complete, though WATT and the Department recommended that acceptance of the report be conditional on additional reporting requirements and improvements for future reports. The Commission can approve the 2025 GETs Report and Implementation Plan with **Decision Option 1** or approve it with conditions in **Decision Option 2**.

All commenters and MTO agreed that transmission owners should continue to file GETs Reports and would iterate and improve on the evaluation methodology over time. AMP provided the following recommendation, which MTO did not object to, and all other commenters appear to agree with:

- The Commission should require Minnesota transmission owners to provide a GETs Report on a biennial basis aligned with the Biennial Transmission Projects Report. **[Decision Option 3]**

In comments, several organizations recommended modified or additional reporting requirements for the 2027 GETs Report and/or for all future GETs Reports. Commenters focused on increasing transparency and access to the GETs Report and underlying information, requested more detail in supporting documents, and recommended that transmission owners integrate GETs into transmission planning and operations in a more proactive and holistic way.

A. Transparency and Data Access

CEOs and WATT expressed concern with the volume of information that MTO marked as trade secret in the 2025 GETs report (pages 19 through 183). CEOs noted that while some of this information is sensitive and should not be publicly available, they questioned the extent of the redactions. CEOs recommended MTO limit their use of trade secret designation in future

reports to improve transparency in the interest of transparency and access **[Decision Option 4]**, and that MTO release information in the 2025 report that does not require trade secret designation **[Decision Option 6].**

WATT initially found the GETs Report incomplete because the large majority of the GETs Report (pages 19-183) was designated as trade secret.[36] Select WATT members then signed an NDA with MTO, allowing them to review the full report. WATT concluded that MTO did identify transmission constraints as directed, but found MTO's assessment of GETs solutions deficient. WATT pointed out that MTO only identified AAR and DLR solutions as sufficiently feasible to be studied in the payback period phase of analysis. TTO was not considered for any constraints. APFC was noted as a potential solution to certain constraints, but MTO stated additional analysis would be required to confirm feasibility and cost-effectiveness. In WATT's view, this additional analysis should have been done and included in the GETs Report to demonstrate MTO had truly evaluated the feasibility and cost effectiveness of APFC for mitigating grid congestion.[37] For this reason, WATT found the report incomplete.

Staff notes that **[Trade Secret Data Begins]** [redacted] **[Trade Secret Data Ends]** the second category of projects "Constraints with Solutions, Payback Period Not Yet Determined" which is discussed in the next section.

The Department reviewed the Biennial Transmission Projects Report and the GETs Report and did not find any notable deficiencies in completeness, and therefore recommended the Commission take no action regarding completeness.[39] In its Initial Comments, however, the Department noted that work papers for calculating the payback period were not included in the initial GETs Report. The Department requested and received these work papers from MTO, and after review, concluded that the GETs Report is complete.[40]

The Department recommended that going forward, the Commission require MTO to include work papers, including derivations of all calculations, as a separate appendix attached to the GETs Report. **[Decision Option 7]** Additionally, to allow the Department to review MTO's payback period calculations and evaluate the cost-effectiveness of projects that do not meet the payback period threshold (for example, to identify if there are projects just over the threshold that may still be beneficial), the Department recommended that in future GETs Reports, MTO include more data in its work papers. DOC requested the following data points for each constraint studied, regardless of whether the payback threshold was achieved:

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[36] WATT Completeness Comments at 3-4

[37] WATT Initial Comments at 2-3

[38] 2025 GETs Report, pp. 58-60 and 71-73

[39] Department Completeness Comments at 1

[40] Department Initial Comments at 16

- Underlying congestion and GETs modeling assumptions,
- Unadjusted congestion charges,
- The type of GET(s) that was studied,
- Solution(s) costs, and
- Calculated project benefits.
  [Decision Option 8]

MTO responded that while they did embed work papers within the GETs Report and have been actively working with the Department to support its analysis, they will plan to include a separate appendix of all work papers in future GETs Reports and will continue to work with the Department to ensure it has the information necessary for its evaluation.[41]

The Department also recommended that MTO include a table summarizing the proposed GETs Implementation Plan in future reports, similar to Table 2 above (Department's Table 1) containing the identified solution's cost, three-year average congestion charge, and the payback period to allow for easier comparison and analysis of proposed deployments. **[Decision Option 9]**

B. Projects Pending Payback Period Determination

In addition to the 12 implementation plan projects (listed in Table 2), MTO included seven projects with constraints and identified solutions, but no payback period determined yet. The Department, WATT, and CEOs expressed concern that payback period calculations were not available for all identified solutions in the 2025 report, and recommended that the Commission require MTO to provide a complete feasibility and payback period analysis for each identified constraint going forward.[42] **[WATT Complete]**

The Department requested that MTO provide work papers and information on the payback period of these in reply comments. MTO stated their evaluation remains underway, but that they would provide the information to the extent feasible and would commit to providing bimonthly updates to the Commission until the evaluation is complete.[43] The Department recommended the Commission require MTO make a bimonthly update on these remaining projects still undergoing evaluation.[44] **[Decision Option 2A]**

C. GETs Integration into Transmission Planning

Several parties criticized the lack of GETs analysis in the BTPR overall, and expressed a desire for transmission owners to better integrate GETs analysis into all levels of planning. As noted

[41] MTO Reply Comments at 5

[42] Department Initial Comments at 8, WATT Reply Comments at 6-7, CEOs Reply Comments at 5

[43] MTO Reply Comments at 5

[44] Department Supplemental Comments at 4

earlier, in 2024, the Minnesota legislature updated Minn. Stat. 216B.2425 to require transmission owners consider GETs among the alternatives for addressing transmission system inadequacies identified in their BTPR.[45] WATT and DOC highlighted that MTO did not evaluate GETs as potential solutions to the 158 inadequacies identified in the broader 2025 BTPR but only for the constraints identified in the GETs Report in Appendix B.[46]

Note that PUC Staff issued an information request December 22, 2025 requesting that MTO members "Provide all documents, including modeling, for every project for which grid enhancing technology was considered as an alternative within the 2025 Biennial Transmission Projects Report." The response indicated that several transmission owners generally consider GETs as an option for all projects but ruled out GETs early in the evaluation process for BTPR projects as "most of the projects were driven by age, condition, or similar asset focused needs, where GETs generally do not provide meaningful benefit."[47]

WATT, DOC, and CEOs argued that GETs, particularly DLR, are no longer "new" and should be more fully integrated GETs into transmission planning and operations. CEOs specifically recommended that MTO members approach GETs in a programmatic way rather than in one-off projects, and work to establish the training, processes, and software needed to incorporate GETs technology into planning, standards, and operations. **[CEOs – Programmatic Deploy]** WATT recommended that in the next GETs Report, transmission owners shall demonstrate that they have deployed or are prepared to deploy DLR. **[Decision Option 10]**

CEOs also highlighted a potential mismatch between the scale of analysis in the GETs Report and the analysis needed to determine utility of certain GETs, especially APFC and TO. The system-wide modeling performed for the GETs Report is limited by necessity to studying a small subset of system conditions that can be expected over the next 5 years. As was discussed in 2025 comments in this docket, PROMOD (the modeling tool used) underestimates congestion—and therefore the benefits of GETs—because it does not capture operational inefficiencies that happen in real time. CEOs stated that APFC and TO generally require AC power flow analysis to determine the true system impacts. To address this, CEOs recommended transmission owners incorporate GETs analysis, at minimum for advanced power flow controllers and topology optimization, into all transmission project development processes as either possible alternatives or supplements during construction.[48] **[CEO – GETs in Tx Planning]**

D. Standardization of Assumptions

In the same vein as CEOs' recommendations to integrate GETs into transmission planning, CEOs

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[45] Minnesota 2024 Session Laws, Chapter 127, Article 42, Sections 19, 20 and 21. Available at: https://www.revisor.mn.gov/laws/2024/0/Session+Law/Chapter/127/

[46] WATT Initial Comments at 3, Department Supplemental Comments at 17

[47] MTO Response to PUC Request for Information, January 16, 2026

[48] CEOs Reply Comments at 3-4

recommended "standardizing line and equipment rating methodologies and assumptions across the state to facilitate better shared learnings across the different transmission owners and better interoperability between GETs deployments"[49] **[Decision Option 15].** CEOs argued that the same reasons for MTO members to file a joint report – a highly interconnected system with shared facilities and paths – are strong reasons to develop standard facility ratings methodologies and assumptions.

MTO did not respond to this recommendation in supplemental comments, but did propose standardizing assumptions on a different topic. MTO recommended that the Commission direct MTO to develop a generic cost estimating guide for GETs, which it said "would improve consistency, transparency, and planning efficiency in future evaluations"[50] **[Decision Option 14].** This recommendation was made in response to (and as an alternative to) Department recommendations to develop terchnology-specifc payback period thresholds. Thresholds are discussed in Section XV.

E. Staff Analysis

Overall, commenters and MTO agreed that transmission owners should publish a GETs Report along with the BTPR. Staff recommends adopting **Decision Option 3.**

Transparency and Data Access:
Staff agrees with WATT and CEO that the large majority of the GETs Report was marked as trade secret which limits the ability of the public to review MTO's analysis and plan. Of course, such limits can be necessary to preserve protected data.

Staff recommends that in future GETs Reports, transmission owners work to publish more summary information in a public manner, such as:

- The number of constraints where each GETs technology type was deemed a feasible and applicable solution.
- Of these, the number of constraints by GETs type that passed the payback period threshold.
- The total cost of the GETs Implementation Plan, and cost by transmission owner.
- Average (or weighted average) calculated payback period for the GETs Implementation Plan

This is reflected in **Decision Option 5.** This type of summary information is useful to the public for understanding the scale of proposals and their cost-effectiveness. Generally, summary information that is not possible to tie back to a particular transmission asset or expected project cost does not need to be treated as trade secret in Commission proceedings. Staff notes that there are procedural benefits to having more information publicly available as well, as it

[49] CEOs Reply Comments at 6

[50] MTO Reply Comments at 8

reduces the volume of data management work and simplifies verbal comments during Commission hearings.

Staff agrees with the Department that including work papers with the initial filing, including the specified additional information in these work papers, and including a detailed summary table of the implementation plan projects would be useful to streamlining the analysis in future proceedings. These are reflected in **Decision Options 7, 8, and 9.**

Projects Pending Payback Period Determinations:
MTO and the Department agree that MTO will file bimonthly updates on its analysis of the seven constraints with identified solutions, but no payback period determined yet. Staff recommends MTO file the payback period results and, if applicable, implementation plans for these projects, when the analysis is complete. **[Decision Option 2A]**

GETs Integration into Transmission Planning:
Staff appreciates CEOs comments regarding the ways in which internal processes may need to evolve to plan for GETs in a programmatic way and integrate GETs technology into planning, standards, and operations **[Decision Options 11 and 12].** However, the Commission typically refrains from prescriptive directives about internal company operations, and in many cases doing so is outside Commission authority (only three members of MTO are public, Minnesota rate-regulated utilities).

Additionally, the MTO response to PUC Staff's December 22, 2025 information request indicated that several transmission owners do consider GETs for all projects, at least in a general way.[51] For these reasons, Staff suggests that if the Commission would like more insight into internal operations and GETs-readiness, it could adopt WATT's recommendation to require transmission owners demonstrate DLR- readiness in the next GETs Report **[Decision Option 10]**, or require each MTO member to describe how they are integrating GETs into planning, project development, standards, and operations in the next report. **[Decision Option 13]**

Standardization of Assumptions:
Staff's understanding is that a generic cost estimating guide would be used as the basis for project cost estimates in future GETs reports and therefore would ensure MTO members are consistent costs and methods of estimating cost. This would improve comparability across companies and could improve the accuracy of cost estimates, especially for companies with less GETs experience. Staff notes however, that in reality not all MTO members may be able to access GETs at the same cost and there is a risk of regulatory lag causing a cost guide to become outdated if the guide and modifications to it require Commission approval. The Commission does not generally request or approve generic cost estimates for these reasons. However, if MTO believe having a generic cost guide would benefit their GETs planning process and improve accuracy of cost estimates, the benefits of developing a guide may outweigh risks. If

[51] MTO Response to PUC Request for Information, January 16, 2026

the Commission supports this idea, the guide could be developed and published as part of the GETs Report, updated each biennium as appropriate, and need not obtain Commission approval of specific cost figures. **[Decision Option 14]**

Regarding CEO's recommendation to establish standard, statewide rating methodologies and assumptions **[Decision Option 15]**, this is a large topic with potentially large, far-reaching impacts. To staff's knowledge, the Commission does not often adopt specific technical standards for electric utilities or providers to use, with the exception of DER interconnection standards which the Commission is directed by statute to establish.[52] Discussion of rating methodologies in this record was quite limited, and therefore Staff recommends taking no action at this time.

X. Technologies for Evaluation in the GETs Report

All commenters – AMP, CEOs, the Department, RMEB, and WATT – critiqued the report for focusing largely on AAR and DLR solutions, and saw this as a lack of effort to fully evaluate other technologies. The Department noted that DLR was the only GETs technology represented in the 12 projects proposed for implementation, and several DLR deployments showed extremely short payback periods. DOC also highlighted that six of the proposed projects would address the constraint with "traditional upgrades…or with AAR, which all transmission owners are now required to implement following FERC Order 881."[53] WATT pointed out that MTO only identified AAR and DLR solutions as sufficiently feasible to proceed to payback evaluation. APFC was noted as a potential solution but without enough information to calculate a payback period. TTO was not considered for any constraints.

The Department also identified that of the 18 Grid North Partners congestion-relief projects that are complete or pending completion, **[Trade Secret Information Begins]** [redacted] **[Trade Secret Information Ends]** The Department expressed concern that, in its view, "many of the MTO did not fully consider GETs until the GETs law was passed"[54] and that the corporate structure of investor-owned utilities (IOUs) could lead these companies to prefer traditional, more capital-intensive infrastructure over GET solutions in order to earn a higher return. MTO disagreed with this assertion, saying that in fact "MTO members have an obligation to ensure reliability in the most affordable manner—regardless of technology" and noting that MTO members, including IOUs, are deploying GETs.[55]

[52] Minn. Stat. §216B.1611

[53] Department Initial Comments at 8

[54] Department Initial Comments at 8

[55] MTO Reply Comments at 2; 10

A. GETs Defined in Statute

While several parties recommended MTO evaluate a broader list of technologies in future GETs Reports, WATT took the opposite view, stating that future GETs Reports should focus on the three technologies currently required by statute (DLR, APFC, and TTO) "as low-hanging fruit until they are part of everyday utility processes."[56] WATT recommended that in the next GETs Report:

- Transmission owners focus on DLR, APFC, and TTO technologies. **[Decision Option 18]**
- Transmission owners provide a complete feasibility and payback period analysis for each identified constraint. **[Decision Option 17]**

B. Advanced Transmission Technologies

The Department found the GETs Report lacking in discussion of new or emerging technologies that are still in the "start-up" phase or only being used in certain areas. It stated such a discussion would be helpful in identifying potential solutions to constraints that are challenging to solve with current tools, and would better set up MTO members to pilot new technology. The Department recommended that future GETs Reports include a discussion new, emerging, and underutilized (but currently commercially viable) GETs, as well as the possibility of developing GETs pilot projects with vendors.[57] **[Decision Option 19]**

MTO stated they are willing to include a high-level discussion of observed trends and general developments in GETs technologies as they relate to system planning and operations **[Decision Option 20]** but do not support requiring detailed analysis of emerging technologies. MTO expressed concern that doing so would unnecessarily expand the scope of the GETs Report, add reporting burdens on MTO members and divert attention away from commercially viable, near-term solutions.[58]

AMP, CEOs, and RMEB recommended the Commission require transmission owners consider a broader range of technologies including reconductoring with advanced conductor/high performance conductor (HPC), reflected in **Decision Options 22 and 24**. AMP argued that these technologies meet the requirements of the 2024 GETs law[59] and can be effective tools for increasing capacity of high-voltage transmission lines and reducing congestion in existing corridors. AMP also noted that HPCs can complement GETs and can benefit from joint study. AMP pointed to a study by AES Ohio which showed that reconductoring a short segment of one

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[56] WATT Reply Comments at 6-7

[57] Department Supplemental Comments at 19

[58] MTO Reply Comments at 10

[59] Minn. Stat. §216B.2425, Subd. 1a: "hardware or software that reduces congestion or enhances the flexibility of the transmission system by increasing the capacity of a high-voltage transmission line or rerouting electricity from overloaded to uncongested lines, while maintaining industry safety standards."

line would solve a constraint and maximize utility of existing DLR.[60] AMP additionally recommended that MTO consult with high performance conductor vendors during development of future GETs Reports, similar to a vendor consultation requirement the Commission approved in 2025 for the instant report. **[Decision Option 23]**

CEOs also encouraged transmission owners to evaluate storage as a grid asset in future GETs and Biennial Transmission Projects Reports, building on the Nobles Grid-Forming Battery study that was included with this report. They noted that a wide range of storage technologies could provide grid benefits—including lithium ion and other electrochemical batteries as well as ammonia production facilities—and urged MTO to study a full range of options.[61]

MTO objected to the idea of requiring evaluation of specific technologies as it could risk promoting 'a solution in search of an issue.' Instead, MTO sought to preserve flexibility for transmission owners to evaluate all available and appropriate technologies. MTO also argued that the current definition of GETs in Minnesota law is broad enough to cover HPC and many other technologies, and therefore it is not necessary to require evaluation of specific technologies in the next GETs Report.[62]

C. Combinations of GETs and Traditional Solutions

The Department noted that the GETs Report considers many GETs paired with traditional upgrades. In some cases, MTO proposed a traditional upgrade that is necessary before AAR or DLR can deliver its full value, such as **[Trade Secret Information Begins]** [redacted] **[Trade Secret Information Ends]** DOC also noted that several projects in the "Constraints with Solution Proposals (Payback Period Not Yet Determined) category are combinations of GETs and traditional projects. DOC's analysis of the GETs Report found that GETs do not significantly increase prices of traditional upgrades when they are paired together. Therefore, DOC suggested that when MTO considers traditional transmission upgrades in a location where GETs could also serve, MTO should compare the cost-effectiveness and timeline of each option and consider whether GETs can offset or delay expensive system upgrades until larger backbone reliability projects like MISO long range transmission lines reach commercial operation.[64] DOC recommended the Commission require that in future GETs Reports MTO consider adding GETs to any proposed traditional upgrade where feasible and where costs would not significantly increase. **[Decision Option 25]**

MTO agreed with the Department's recommendation to consider adding GETs to traditional upgrades if feasible and cost effective, but argued this should occur during the alternatives

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[60] AMP Reply Comments at 4

[61] CEOs Reply Comments at 5-6

[62] MTO Supplemental Comments at 1-3

[63] GETs Report at 54-56

[64] Department Initial Comments at 22

analysis in certificate of need (CN) proceedings for high voltage transmission lines rather than in GETs Reports[65] **[Decision Option 26].** In contrast, the Department said that "confining GETs analysis to individual CN dockets produces a fragmented record that denies the public and decision makers a meaningful opportunity to assess how these technologies can shape the bulk power system as a whole."[66] The Department supported analyzing GETs as alternatives in CN proceedings *in addition* to study in the GETs Report and, more broadly, in the BTPR as required by recent updates to Minn. Stat. § 216B.2425, subd. 2.

The Department took issue with the characterization of AAR at a "GET" in the GETs Report "FERC Order No. 881 requires transmission providers to implement AAR as a baseline compliance obligation" by July 2025.[67] DOC recommended that the Commission order that AAR are ***ineligible*** for inclusion in future GET report implementation plans as they are a required technology not a novel or innovative solution **[Decision Option 27].** MTO disagreed, saying that it is beneficial to include AARs as part of overall suite of transmission planning tools studied. MTO pointed out that in some cases, seasonally adjusted AARs solve a constraint for less cost than DLR would. In MTO's view, studying AAR is consistent with the Commission's 2025 GETs Order which required transmission owners to evaluate GETs, traditional solutions and combinations thereof, and excluding it would unnecessarily limit the range of potential solutions.[68]

D. Staff Analysis

Staff agrees that MTO should provide complete feasibility and payback period analysis for each constraint in the next GETs Report. Staff suggests MTO also provide complete implementation details for applicable solutions as reflected in **Decision Option 17.** MTO had a shorter turn-around time for developing the 2025 report than will be the case going forward, and Staff expects future reports will be simpler to develop now that processes and methodologies are more established.

Technologies for Evaluation

While all commenters critiqued the lack of analysis on GET types outside of DLR and AAR, they were divided on whether to encourage MTO to focus on the "low hanging fruit" GETs (APFC and TTO, in addition to DLR) or whether to require MTO expand the list of GETs and advanced transmission technologies being evaluated. However, as MTO noted, the statutory definition of GETs is broad enough to encompass advanced transmission technologies, so the Commission may not need to be prescriptive about which technologies it would like to see evaluated.

Staff recommends the Commission at minimum approve MTO's recommended reporting

[65] MTO Reply Comments at 8

[66] Department Supplemental Comments at 16

[67] Department Initial Comments at 22

[68] MTO Reply Comments at 9

requirement (a discussion of emerging GETs technologies) **[Decision Option 20]**. However, in Staff's view, a broader reporting requirement could be useful; the discussion of GETs technology options and MTO members' deployment efforts so far was rather limited in this report, though MTO members have provided detailed information on GETs pilots elsewhere.[69]

Given the subject of this proceeding, and prior Commission orders requesting this information in future BTPRs,[70] Staff finds it would be useful to include more robust information in future GETs Reports. This could be combined with reporting on emerging technology. Staff offers Decision Option [Staff – Tech Overview] to direct reporting on:

- A summary of grid enhancing technologies available and in development,
- A summary of each technology's commercial readiness and how it is being deployed,
- A summary of each MTO member's GETs deployment efforts and results to date,
- A discussion of whether each MTO member has studied or are considering any advanced transmission technologies,
- A discussion of research collaboratives MTO members may participate in,
- What MTO members see as being the best use case and/or nearest-term opportunity for GETs and advanced transmission technologies on their system.
  [Decision Option 21]

<u>Reporting on Approved GETs Implementation Plan Projects</u>

As this proceeding and subsequent GETs Reports may approve additional GETs deployments, Staff finds it would also be appropriate to collect information on any new projects that the Commission approves. Staff suggests that in future GETs Report, MTO provide a summary of each project that was approved, an update on project status, and summarize results when available.

Specifically, Staff recommends MTO provide:

- A discussion of each approved project, observations of the congestion impact or other results after implementation, and lessons learned.
- A table or attachment listing for each of the approved GETs Report projects:
  - Name of project
  - Approval year
  - Transmission owners
  - High-level summary of technology being deployed
  - Project status and estimated or actual in-service date
  - Estimated cost at time of approval
  - Actual cost
  - Calculated three-year average congestion charge at time of approval
  - For projects in service for 12 months or more: Congestion charge based on the

[69] See for example, presentations given to the Commission at the February 3, 2026 Planning Meeting.

[70] *In the Matter of the 2023 Minnesota Biennial Transmission Projects Report, Commission Order Accepting Report,* June 7, 2024, Docket No. E999/M-23-91, at Ordering Paragraph 6

year after implementation
[Decision Option 16]

Combinations of GETs and Traditional Solutions

MTO and the Department agree that it makes sense to consider adding GETs to traditional upgrades if feasible and cost effective, but disagreed about whether this should occur during alternative analysis in CN proceedings or also in the GETs Report. Staff note that several solutions evaluated in the GETs Report do consider and evaluate the addition of GETs to a traditional solution. In Staff's view, the Department's recommendation **[Decision Option 25]** is reasonable as it would not require a new type of analysis—though it would require transmission owners to consider GETs in each case. If GETs are not feasible or would increase costs significantly, that would be noted in the project description.

While Staff agrees with the Department that AAR implementation is now required and should be widely deployed in coming years, Staff does not recommend excluding it from analysis in future GETs Reports, as is suggested in **Decision Option 27.** In 2025, the Commission directed MTO to evaluate GETs and traditional solutions and combinations thereof for the GETs Report to better arrive at the most beneficial solutions. Evaluating AAR as one of the tools available to MTO is consistent with this directive.

XI. Constraints to Evaluate

A. Constraints with Forecasted Congestion

The Department, CEOs and WATT raised concerns that GETs solutions were not being developed to mitigate planned outages, such as those for LRTP line construction.[71] Given the relatively short payback period for DLR, these commenters suggested it is appropriate to use as a mitigation during temporary outages, especially as DLR hardware can often be relocated as needed. Similarly, RMEB urged the Commission to require GETs analysis for all known transmission constraints and needs, including related to LRTP construction **[Decision Option 29A].**

MTO stated that transmission owners already consider congestion impacts and mitigation options including GETs as part of transmission planning and outage coordination. MTO argued it is premature to identify specific outage-related mitigations for Tranche 2.1 projects as these routes are not yet approved, but stated that GETs will be considered as the projects progress.[72] The Department disagreed, arguing that early analysis will strengthen CN applications.

WATT and CEOs also recommended that in future Reports, MTO study GETs for constraints that have high levels of congestion in future modeling, regardless of whether they meet the 168-

[71] Department Supplemental Comments at 16, CEO Reply Comments at 3

[72] MTO Reply Comments at 8

hour threshold for historical years[73] **[Decision Option 29B].** CEOs asserted that MTO was being overly conservative in not developing solutions for these constraints, as in its view, anticipated load growth will exacerbate constraints and make it likely that future congestion meets or exceeds this forecast.[74]

WATT noted that there were eight constraints in the 2025 report that only met 168 hours of congestion in future modeling, and that it was not clear whether there is overlap between these locations and those identified in MISO's near-term congestion report. WATT recommended that in future GETs Reports, MTO discuss recent MISO congestion studies, identify any overlapping locations with the GETs study, and describe actions MTO members are taking to address congestion in areas identified by MISO **[Decision Option 30].** Relatedly, for constraints that are driven by construction or outages, WATT recommended that MTO identify the expected duration and end date of the outage **[Decision Option 31].**

B. FTR Binding Constraints

The Department pointed out that MTO only evaluated congestion costs and the impact of FTR hedging in locations where there has been at least 168 hours of congestion in any of the past three years. DOC asserted that there could be areas with high or volatile congestion pricing that experience fewer than 168 hours of congestion annually, and that MTO should evaluate congestion solutions based on each location's financial impact rather than the number of hours. DOC acknowledged that the 2024 GETs Law specified transmission owners must include locations with more than 168 hours of congestion, but argued the Commission can establish additional thresholds for constraint inclusion in future GETs Reports.[75]

In Supplemental comments, the Department suggested that FTR auction results could be a useful indicator of transmission system inefficiencies that market participants expect to persist into the future. A location identified as a binding constraint[76] in an FTR auction indicates that market participants expect current transmission topology cannot fully accommodate demand for power flow.[77] The Department surmised that FTR binding constraint locations are likely to be facilities preventing full utilization of lower-cost generation resources.

The Department used datasets from MISO and from MTO members to evaluate binding constraints tied to the service territories of Minnesota utilities identified in FTR auction results during Fall 2023 through early 2026. The Department found 1,369 constraints, of which 199

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[73] WATT Reply Comments at 5, CEOs Reply Comments at 5

[74] CEOs Reply Comments at 5

[75] Department Initial Comments at 19

[76] A binding constraint occurs when transmission facilities reach a flow limit (such as a thermal, voltage, or stability limit) based on the market's economic dispatch order, and dispatch must be adjusted to avoid exceeding the limit. Binding constraints cause LMP differentials on each side of the constraint.

[77] Department Supplemental Comments at 10

were studied for the 2025 GETs Report. Of these, DOC found that 964 were binding for fewer than 168 hours, including 80 of the constraints studied in the GETs Report. DOC asked MTO to explain the discrepancies between binding hours in this dataset and hours of congestion used in the GETs Report. DOC also identified that many constraints are only partially in Minnesota, and suggested that study of these locations could provide useful insight into the drivers and solutions of congestion that Minnesota ratepayers ultimately pay for.[78]

The Department also evaluated, for the constraints entirely within Minnesota, the total capacity and marginal cost of constraints in the FTR binding constraint list that were not studied in the 2025 GETs Report. DOC found these constraints totaled approximately 211,500 MW and were responsible for approximately $1.27 million in added marginal costs during the 2023-2026 timeframe.

The Department found this evaluation useful and recommended that MTO analyze binding constraints identified in the annual FTR allocation process as part of a more comprehensive constraints analysis in future GETs Reports. DOC suggested that GETs solutions for FTR binding constraints "may present a compelling regulatory argument: these technologies can provide 'bridge capacity' or permanent relief more rapidly and at a lower cost than traditional 'poles and wires' builds, directly lowering the congestion premiums that would otherwise be passed through to ratepayers."[79]

The Department also asserted that Shadow Price (the production cost savings from relieving a constraint by 1 MW) may be an effective metric for identifying high-value locations for GETs deployment—a high shadow price suggests that a relatively small increase in capacity rating could yield large economic benefits.[80]

The Department recommended the Commission order that in future GETs Reports, MTO consider constraints identified in the FTR binding constraint list published by MISO, in addition to the data sources used in the 2025 GETs Report to identify potential opportunities for GETs implementation. **[Decision Option 32]**

C. Staff Analysis

<u>Constraints with Forecasted Congestion</u>
Staff agrees that in theory, targeting GETs to locations where congestion is expected in the future (rather than only where it has been historically observed) is entirely logical. However, Staff has concerns about whether this is feasible in practice given available tools. The Commission considered this issue to an extent in 2025 when adopting a methodology for transmission owners to use in their 2025 GETs Report. At that time, the Commission directed

[78] Department Supplemental Comments at 10-13

[79] Department Supplemental Comments at 10

[80] *Ibid.*

transmission owners to focus on locations with historical congestion. That proceeding included discussion of whether production cost modeling could be used to identify future constraints and/or whether production cost modeling results could be used as the basis for payback period calculation. Staff noted at the time that there appeared to be consensus that typical modeling techniques lack accuracy in predicting specific amounts of future congestion, but that modeling is useful for evaluating long term trends and relative severity. Staff suggests commenters interested in GETs for future constraints provide more information about the absolute accuracy of production cost modeling for identifying limiting facilities in future conditions, and/or present information on modeling techniques or screening procedures to improve accuracy.

In contrast, transmission owners can identify facilities that will be impacted by planned outages and construction with much greater confidence. Staff agrees that it would be beneficial for transmission owners to explicitly consider GETs as mitigations during LRTP construction outages and similar events and report on this in the next GETs Report **[Decision Option 29A]**.

Similarly, Staff supports WATT's recommended reporting requirements comparing GETs Reports constraints to MISO-identified near term congestion points **[Decision Option 30]**, and to provide expected end dates for planned outages that are driving constraints identified the report **[Decision Option 31].** Staff expects this information will help the Commission and stakeholders better understand system conditions and pathways for congestion mitigation.

FTR Binding Constraints

Staff agrees that FTR binding constraints could provide a useful starting point for identifying constraints worth studying for mitigation projects, as this classification means the RTO has identified that equipment is limiting power flow compared to optimal generator dispatch. The Department's analysis provides an interesting overview of FTR binding constraints in Minnesota categorized by the number of binding hours and by utility. The Department's recommendation is reflected in **Decision Option 32.**

However, the Department identified over 1,000 binding constraints in Minnesota during the three-year historical period evaluated. In comparison, the 2025 GETs Report evaluated 66 constraints, and the summary of these evaluations totaled close to 200 pages. In order to operationalize the Department's recommendation to evaluate FTR binding constraints without over-burdening transmission owners and regulatory agencies, Staff believes it would be useful to provide MTO with flexibility to prioritize or criteria for prioritizing among the many binding constraints.

Such criteria could include:

- Constraints with the highest number of binding hours
- Constraints with the highest shadow prices
- Constraints that score high on both binding hours and shadow price

The Commission may wish to ask parties about this at the Agenda Meeting. If it is interested in further exploration of how to evaluate FTR binding constraints in future GETs Reports before

ordering MTO to do so, it could adopt **Decision Option 33,** to direct MTO to provide a thorough discussion of whether and how it could use FTR binding constraints to inform the list of constraints evaluated for GETs deployments in future reports.

XII. Payback Period Methodology

A. Inclusion of Additional Benefits in the Payback Period Calculation

The Department found the three-year average adjusted congestion charge to be an incomplete measure of the overall value of GETs or other transmission solutions and asserted that "GETs provide substantial value to ratepayers that are not captured by the current methodology," which "should be accounted for when evaluating GET implantation plans."[81] The Department pointed to benefits including avoided market purchases of replacement energy, avoided curtailment payments to PPA counterparties, increased production tax revenue for counties, and reduced curtailment of (and increased generation from) renewable energy resources.

The Department also pointed out that local communities benefit from GETs deployments that reduce curtailment, while they do not benefit from FTRs. The Department argued that without considering broader benefits, the GETs Report's current methodology may understate the value of physically mitigating congestion. Potential benefits of *physical* solutions also include mitigation of severe congestion events and reduced congestion volatility over time, so the Department suggested MTO should perform a more comprehensive assessment that considers variability and tail risk in congestion costs.

Accordingly, the Department recommended that MTO calculate the payback period of potential GETs deployments using a range of benefits resulting from *physical* solutions to congestion in addition to consideration of financial instruments (i.e., FTRs)[82] **[Decision Option 35]**. CEOs and RMEB agreed that the payback period methodology should be expanded to consider additional benefits, especially reduction of curtailment.[83] RMEB noted that persistent transmission congestion in southwestern Minnesota poses serious risks to RMEB members tax revenues, but that municipalities cannot financially hedge against curtailment risk like MTO members can. RMEB recommended that MTO include potential losses or gains to county and municipal tax revenue in the payback period calculation going forward **[Decision Option 36]**.

In reply comments, MTO interpreted the Department's recommendation as a request to report congestion charges and calculate payback periods both with and without adjustment for FTR revenues. MTO did not object to showing such additional calculations for informational purposes, but stated that the 2025 GETs Order required historical congestion (and the GETs

[81] Department Initial Comments at 17

[82] Department Initial Comments at 18

[83] CEOs Reply Comments at 3, RMEB Reply Comments at 2

payback period) be calculated by netting FTR revenue from the congestion charge.[84] See Section XIII, FTR Adjustment Methodology, for more discussion on this topic. Overall, MTO recommended maintaining the current payback period methodology **[Decision Option 34]**.

In Supplemental comments, the Department clarified that it agreed with MTO that FTRs should be netted from the congestion charge for purposes of the payback period calculation. Rather, the Department recommendation is to include additional factors (i.e., avoided cost of replacement energy, avoided curtailment payments, and increased deliverability of renewables) in the payback period calculation to better represent the full potential benefits. The Department provided an example calculation showing how replacement energy and curtailment payments could be integrated into the payback period formula[85] and recommended the additional metrics be used in the decisive payback period calculation, not just for informational purposes.

The Department recommended that the Commission order:

- In future GETs Reports, MTO shall calculate the payback period of potential GETs deployments using a broader range of benefits and costs that result from physically addressing the congestion. **[Decision Option 35]**
- MTO shall file for informational purposes payback period calculations for the constraints identified in the 2025 GETs Report, using a broader range of benefits and costs that would result from physically addressing the congestion. **[Decision Option 38]**

B. Quantifying Potential Curtailment Payments

To further evaluate the impact of curtailment payments on potential cost-effectiveness of GETs, the Department also recommended the Commission require MTO to provide information about PPAs with, or curtailment payments made to, generators on transmission lines where MTO members also hold FTRs. **[Decision Option 39]**

In reply comments, MTO asserted that this recommendation is outside the scope of the GETs Report and Minnesota legislation. MTO expressed concern that introducing this information into the GETs Report would raise the issue of curtailment impact on local government production tax revenues. MTO view the GETs Report as an inappropriate venue for that conversation and stated that "the Commission has been clear that congestion and GETs dockets are not an avenue to address local government tax impacts."[86]

In its Supplementals Comments, the Department reiterated its recommendation and argued that providing this information is consistent with the 2024 GETs Law and 2025 GETs Order. DOC

[84] MTO Reply Comments at 6

[85] Department Supplemental Comments at 6 (example is Trade Secret).

[86] MTO Reply Comments at 3, footnote 5, citing to the Commission's March 6, 2025 Agenda Meeting in Docket No. E999/CI-24-316.

pointed to language in the GETs Law that requires an implementation plan be developed for GETs solutions "at which the payback period is less than or equal to a value determined by the commission, *in order to maximize transmission system capacity*." (Emphasis added.)[87] The Department also noted the 2024 GETs Law asks transmission owners to estimate "the increased cost to ratepayers resulting from the substitution of higher-priced electricity."[88] The Department interpreted these clauses as expressing a preference for *physical* congestion mitigation and a directive to evaluate the costs to ratepayers of replacement energy related to curtailment.[89]

The Department also pointed to the Commission's 2025 Order as supporting its recommendation for evaluating potentially-impacted PPAs, particularly the following phrase: "with an expectation that additional analysis and discussion will better inform the value and cost effectiveness of technologies that are designed for the purposes of reducing congestion to increase the availability of the lowest-cost electricity."[90] DOC expressed an expectation that curtailment payments are likely to increase as renewable generation increases, and stated that data on the scale of this cost is pertinent to the GETs evaluation.

C. Staff Analysis

Staff understands the Department's recommendation **[Decision Option 35]** to use a range of benefits resulting from *physical* solutions to congestion to, in essence, be a recommendation to add two or three new metrics into the payback period calculation. These additional metrics would be:

- the value of avoiding replacement energy purchases,
- the value of avoiding curtailment payments, and
- the value of improved renewable energy deliverability.

The Department's example calculation on page 6 of its Supplemental Comments illustrates how the first two could be incorporated into the payback period calculation Staff believes the first two metrics would also be relatively simple to quantify for past years using historical data.

The Department was less specific about inclusion or quantification of the third metric (renewable deliverability) in its comments. Staff notes that it may be possible to use production cost modeling and environmental externality values to quantify differences in societal costs resulting from increased deliverability and reduced renewable curtailment. However, prior rounds of comment in this docket highlighted difficulties with production cost modeling accurately forecasting curtailment or congestion levels, and there was limited record development on this topic in the current proceeding.

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[87] Department Supplemental at 5, citing to 2024 GETs Law, Subd.2, clause (6).

[88] 2024 GETs Law, Subd.2, clause (6)

[89] Department Supplemental Comments at 5

[90] 2025 GETs Order at 4

Staff has two reservations about expanding the payback period methodology as suggested:

- The Department's recommendation in Initial Comments was not entirely clear, or at least, MTO appear to not have understood the Department's intention. As a result, record development on the specific recommendation is somewhat limited.
- It is not clear whether or to what extent the current method of using FTR-adjusted Congestion Charge to quantify GETs benefits may already account for (albeit in a different way) the cost of replacement energy. Congestion charge is a product of the MW limit and the shadow price, which represents the production cost savings ($/MWh) that could be achieved by increasing capacity by 1MW. There has not been discussion in this record about whether replacement energy costs are generally captured by the congestion charge or would be additive to it.

That said, Staff supports the goal of being more comprehensive and accurate and agrees there is a public interest reason to avoid systematically understating GETs benefits. The Commission could:

- Adopt the Department's recommendation with **Decision Option 35**
- Require evaluation of the Department's recommendation and how to appropriately quantify such additional metrics with **Decision Option 37** (a staff alternative), or
- Take no action on this issue at this time and potentially revisit in the 2027 GETs Report.

Regarding the Department's recommendation that MTO make an informational filing with the payback periods for constraints identified in the 2025 GETs Report when using these additional metrics, if the Commission also adopts Decision Option 35, Staff sees no problem with ordering this for informational purposes. Staff offered two potential dates when the informational filing could be made: along with the 2027 GETs Report or by October 1, 2026, should the Commission prefer to see this information in advance of the 2027 Report [**Decision Option 38A or 38B].**

Regarding RMEB's recommendation to include tax revenues or costs in the payback period calculation **[Decision Option 36]**, Staff is sensitive to the dramatic impact that curtailment can have on municipal revenues, but does not find it appropriate to include this factor in the payback period analysis, which aims to identify how many years it will take for an investment to "pay off" for a transmission owner's customers. Benefits and costs accruing to non-customers are appropriate to consider in societal cost-effectiveness tests, but at this time, the GETs analysis uses a payback period calculation as this method was prescribed in the 2024 GETs Law.[91]

Regarding the Department's request for information on curtailment payments and PPAs that may exist with generators located on transmission lines where MTO members also hold FTRs **[Decision Option 39]**, Staff questions if this information can be disclosed among MTO members without revealing trade secret information on contract terms. It is possible information

[91] 2024 GETs Law, Subd. 2 clause 5

requests between the Department and transmission owners would be a simpler method of ascertaining the relevant information. Staff also wonders whether the Department is only interested in locations where transmission owners have FTRs, or whether the information would be applicable (in theory) to any constraints identified in the GETs report. Overall Staff finds this recommendation requires more development and specificity.

XIII. FTR Adjustment Methodology

A. Overview

The Department provided a detailed explanation of how FTRs operate and how MTO applied FTRs to the congestion charge of each constraint.

> 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.
>
> 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.32 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.[92]

The Department interpreted MTO's use of FTR profit (netting FTR charges against FTR revenue) as manipulating FTR data to make congestion appear as a negative attribute to the system.[93] DOC argued that the Commission's 2025 GETs Order required subtracting only FTR/ARR revenue (not profit) from the congestion charge, and that the unadjusted FTR/ARR revenue would provide better insight into the full costs of congestion relative to the revenues from

[92] Department Initial at 9

[93] *Ibid*

transmission ownership and hedging. DOC recommended MTO provide work papers showing both FTR charges and revenues to enable this more comprehensive evaluation **[Decision Option 43]**.

The Department also took issue with MTO's approach of setting the congestion charge to zero when FTR profits exceeded the congestion charge. DOC stated that in cases where FTR revenues exceeded congestion charges, the congestion hedge resulted in a net financial gain to the system rather than a zero-cost outcome. DOC requested via information requests MTO's *unadjusted* FTR revenues and charges by contract to fully capture congestion outcomes under both prevailing and countervailing flows. Because the GETs payback period is calculated based on a three-year average of congestion charges, DOC argued it is important to understand the gross components of hedging performance.[94]

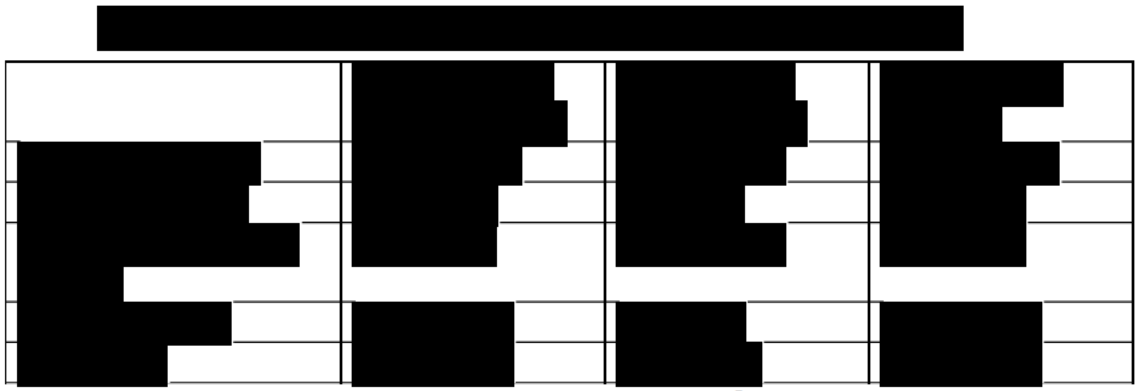
The Department analyzed annual FTR revenues and payments for each company that provided information: Xcel, GRE, Otter Tail, Minnesota Power, and MRES. For each company, DOC aggregated positive revenues (congestion was in the prevailing flow direction) and negative revenues (congestion was in the counterflow direction) each year 2022-2024.

[Trade Secret Information Begins]

[redacted]

[94] Department Initial at 10

[95] Department Initial at 17



[Trade Secret Information Ends]

B. Methodology Adjustments

As noted earlier, the Department and MTO appeared to agree with continuing to net FTR profits from congestion charges for future GETs Reports **[Decision Option 40]**. Regarding MTO's approach of using source and sink shift factors to allocate congestion revenues to specific constraints, the Department recommended continuing iteration to refine the methodology but did not raise any specific concerns.

WATT recommended the Commission adjust the payback period methodology to remove netting of FTR revenues from the congestion charge:

> As this Report demonstrates, FTRs are an imperfect hedge against congestion. Regardless of how the transmission owner hedges, the congestion still represents system inefficiency and limits… Netting FTR revenues obscures the true magnitude of the inefficiency from regulators, ratepayers, and the public.

WATT argued that transmission owners and the Commission should prioritize improving efficiency of the system above mitigating financial losses, and said that selecting grid upgrades only after accounting for FTRs distorts the results, possibly allowing constraints that could be resolved to continue. **[Decision Option 42]**

As noted earlier, MTO expressed willingness to provide congestion charges and payback periods without FTR adjustment for informational purposes **[Decision Option 41]** but pointed out that the 2025 GETs Order required historical congestion (and the GETs payback period) be calculated by netting FTR revenue from the congestion charge.[97]

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[96] Department Initial Comments at 11-15, Summarizing Tables 2-6

[97] MTO Reply Comments at 6

C. Systemwide vs. MTO FTR Outcomes

DOC did, however, disagree with MTO that FTR information is not available for all market participants. DOC asserted that "publicly available MISO auction results and Day-Ahead LMP data allows for the calculation of FTR revenues across all market participants,"[98] which could provide a more complete picture of how congestion is financially managed in the market. (Staff notes this would mitigate the first potential deficiency of its methodology cited by MTO.)

To enable comparison of utility-specific FTR performance relative to systemwide hedging outcomes, the Department recommended that the Commission direct MTO to include in future GETs Reports separate reports showing adjusted congestion charged when a) considering FTRs held by MTO members and b) considering FTRs held by all MISO market participants. **[Decision Option 44]**

In their reply comments, MTO stated this recommendation was outside the scope of the GETs Report, and that including data from all MISO participants would "dilute the relevance of the analysis" and "would introduce substantial noise without improving insight into the physical performance of the current and future Minnesota transmission system."[99]

The Department disagreed, and clarified that it sought two separate reports of FTRs and FTR-adjusted congestion charges.[100] The first would show adjusted congestion charges for the MTO-owned FTR portfolio, and the second would show adjusted congestion charges for all FTRs available in the market. The Department argued this information would help the Commission and stakeholders understand how effectively MTO members have hedged their congestion risk and how efficient their trading strategies are.

D. Staff Analysis

Staff appreciates the Department's analysis of FTRs, as it is not a topic that regularly receives in-depth evaluation in Commission dockets – although the topic has been receiving closer evaluation in automatic fuel charge proceedings in recent years. There are two contested issues the Commission will need to weigh with regard to FTRs in this proceeding:

1. Whether to continue to net FTR profits from the congestion charge for purposes of calculating the cost of congestion at each identified constraint;
2. Whether to require MTO to provide a report showing congestion charges adjusted for MTO members' FTR performance, and a report showing congestion charges adjusted for *market-wide* FTR performance.

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[98] Department Initial Comments at 16

[99] MTO Reply Comments at 6

[100] Staff interprets the word "reports" here to mean two attachments to future GETs Reports, rather than two entire GETs Reports.

On the first question, the Department generally agreed with MTO's approach to allocating FTRs to specific constraints and adjusting the congestion charge by the FTR profits, but suggested MTO should provide work papers showing both total costs and total revenues to allow for better assessment of their FTR portfolios. In contrast, WATT argued for removing the FTR adjustment from the congestion charge in future reports.

Whether to net FTR profits from the congestion charge is a policy question for the Commission. On one hand, netting FTR profits provides a more accurate accounting of what transmission owners (and their customers) are paying as a result of congestion. On the other hand, netting FTRs has the potential to hide the true impact of congestion and to make some constraints look relatively milder and others more severe. Congestion prevents lower-cost generation from being delivered, regardless of whether the congestion was hedged.

In Staff's view both methods (netting FTRs and not) have logic and potential drawbacks. The Commission should weigh whether it wants to prioritize locations with greatest congestion (and the largest capacity, given this is a factor in calculating congestion charge) or those with highest recent financial costs to customers. If the Commission wishes to focus the next GETs Report on constraints with highest recent financial costs, it should adopt **Decision Option 40** (continue to net FTRs) and if it wishes to focus the report on areas with highest congestion charges, it should adopt **Decision Option 42**. If selecting **Decision Option 40**, the Commission may also select **Decision Option 41** to have MTO provide payback periods using unadjusted congestion charges for informational purposes.

Regarding the Department's recommendation to provide two reports allowing comparison of MTO member's FTR results with market-wide results, **Decision Option 44,** Staff is unsure whether findings from such an analysis would be actionable by the Commission in this docket. In 2025, the Commission ordered public utilities to file additional information on ARR and FTR hedging strategies, as well as other efforts to mitigation congestion (including GETs) in their next fuel forecast petitions, which were filed May 1, 2026.[101] These proceedings may be an equally or more suitable proceeding for evaluation of FTR hedging effectiveness and better link this analysis to potential remedies, if deficiencies are identified.

Staff also has questions about 1) the scale of potential improvements that could be achieved, as the Department's analysis in this docket indicated most utilities are generating net profits through their FTR portfolio, and 2) about the level of computational work required to calculate shift factors for each FTR in the MISO market for each constraint identified in the GETs Report. The Commission may wish to ask the Department and MTO about their capacity to perform this

[101] See*: In the Matter of Xcel Energy's Petition for Approval of its 2024 Annual Fuel Forecast and Monthly Fuel Cost Charge*s, Commission Order, August 7, 2025, Docket No. E002/AA-23-153; *In the Matter of Minnesota Power's Petition for Approval of the Annual Forecast of Automatic Adjustment Charges for the Period of January 2024 through December 2024,* Commission Order, August 7, 2025, Docket No. E015/AA-23-180; *In the Matter of Otter Tail Power Co.'s Petition for Approval of the Annual Forecasted Rates for its Energy Adjustment Rider, Rate Schedule Section 13.01,* Commission Order July 28, 2025, Docket No. E017/AA-23-181

analysis, what they expect to learn from it, and what actions could be taken based on it, during the hearing.

XIV. Payback Period Threshold

A. Department

MTO used a five-year payback period as the threshold for GETs solutions included in its implementation plan, i.e., for which MTO developed a cost estimate and schedule. DLR was the only GETs technology included in the implementation plan, which the Department speculates could be due to other GET types not meeting the five-year threshold at this time. The Department pointed out that the 2025 GETs Order directed MTO to include a schedule and cost estimate for projects meeting the five-year threshold, and also 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 a value appropriate to the specific technology and potential application."[102]

The Department noted that the GETs category includes a range of different technology types and that some types may not be likely to meet a five-year payback period but would still provide benefits to the system. Advanced conductors, for example, have higher upfront capital costs than GET technologies listed in Minnesota statute but also provide benefits beyond relieving congestion. By enabling significant increases in transmission capacity in existing rights of way, advanced reconductoring can improve reliability and provide increase operational flexibility and re-routing options. The Department provided a hypothetical example where a $20 million advanced reconductoring project has estimated benefits of $3.9 million per year, and thus has a 5.13 year payback period. Under the current framework, this project would not be considered for the GETs implementation plan despite delivering large annual benefits.

The Department is concerned that having a bright line at five-year payback period could leave out two categories of valuable GETs projects: (1) GETs that are more cost-effective than traditional transmission upgrades, but miss the 5-year threshold, and (2) inexpensive pilots of new technology that may not be cost-effective at early stages. While the first category may unintentionally lead to less cost-effective traditional investments, the second category could hinder the adoption necessary to drive down the cost of new technologies over time.[103]

To address its concerns, the Department recommended the Commission either:

A. Direct MTO to use a payback period threshold appropriate to each specific technology type and provide a cost estimate and implementation schedule for each GETs deployment that meets the technology-appropriate threshold. **[Decision Option 45]**

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[102] 2025 GETs Order, Ordering Paragraph 4c

[103] Department Initial Comments at 20

OR

B. Delegate authority to the Executive Secretary to open a comment period to establish technology-specific payback period thresholds for each GET technology type including, but not limited to, dynamic line rating, power flow control, topology optimization, and advanced reconductoring. **[Decision Option 46]**

AND

C. Require MTO to provide cost estimates and implementation schedules for GETs solutions using the technology-appropriate payback period threshold. **[Decision Option 47]**

MTO opposed replacing the five-year threshold with technology or constraint-specific Thresholds, stating that this would "reduce transparency, complicate comparisons across projects, and invite disputes over how individual thresholds should be set."[104] The Department disputed each of these assertions, arguing that the GETs Report already lacks transparency into how engineering decisions are made, that projects in the report are inherently not very comparable, and that in its opinion, further deliberations will create a better understanding of the value of different GETs.[105]

MTO also supported continuing to use the five-year payback threshold because it "focuses on near-term congestion relief opportunities that may not be addressed through MTEP, LRTP, or Market Efficiency Project (MEP) projects. This approach enables identification of cost-effective local solutions while maintaining a consistent, technology-neutral screen."[106] Lastly, MTO expressed concern about diverting MTO resources toward less economic projects and could undermine the purpose of the payback period test set out in statute.

The Department disagreed with these concerns, arguing that the five-year threshold is not "technology-neutral" because it does not take into account the different benefits and costs of different GETs, and could bias the selection of GETs to the least expensive and most near-term applications (i.e., toward DLR, and away from technology like advanced reconductoring).[107]

Instead of developing technology-specific thresholds, MTO recommended that the Commission direct MTO to develop a generic cost estimating guide for GETs, which it said "would improve consistency, transparency, and planning efficiency in future evaluations without weakening the established economic screens."[108] **[Decision Option 14]** The Department expressed skepticism that such a guide would be useful, and confusion at its intent.

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[104] MTO Reply Comments at 7

[105] Department Supplemental Comments at 14

[106] MTO Reply Comments at 7

[107] Department Supplemental Comments at 15

[108] MTO Reply Comments at 8

B. Staff Analysis

Ordering paragraph 4c of the 2025 GETs Order directed MTO to include a schedule and cost estimate for projects meeting the five-year threshold, and also 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 a value appropriate to the specific technology and potential application."[109] Staff infers that the Commission was interested in seeing what technology-specific payback period thresholds may look like, and how the list of proposed projects would change using technology-specific thresholds.

Should the Commission wish to continue to evaluate this issue, Staff recommends **Decision Option 45** a**nd subpart 45A**, which would direct MTO to include a comprehensive explanation of how it arrived at each technology-appropriate threshold. Staff prefers this avenue (addressing this issue during the 2027 GETs proceeding) over opening a new comment period for administrative and regulatory efficiency.

If the Commission prefer to direct MTO to use a 5-year payback period threshold, it can do so with **Decision Option 48.**

GUIDE TO THE DECISION OPTIONS

The Decision Options are organized in categories mirroring each section of the briefing papers. In the first section, the Commission should choose whether to approve the 2025 GETs Implementation Plan (the 12 projects proposed for deployment) and whether to accept the 2025 GETs Report as complete, or to require bimonthly updates on pending analysis. **[Decision Option 1, or 2 and 2A]**

If the Commission agrees that MTO should file future GETs Reports along with the BTPR, it should select **Decision Option 3.** In this case, the Commission should also make certain decisions about the methodology to be used in future GETs Reports, or at least, in the 2027 GETs Report.

Staff notes in each subsection of the decision options whether the Commission should "select" or "consider" decision options under that topic. "Select" indicates that a decision on the topic is necessary to provide direction for future reporting. "Consider" indicates that a decision on the topic is optional. Staff does not make this distinction to suggest that the Commission skip optional topics, as many of the decision options within them are intended to provide a more comprehensive, more accurate, or more beneficial report. Rather, the distinction is intended to help the Commission better navigate the decisions before it.

[109] 2025 GETs Order, Ordering Paragraph 4c

Below, Staff lists the topics under each category of decision options, and notes whether the Commission should select a decision option in that topic, or may consider the options.

I. Filing Requirements for Future GETs Reports – select either

II. Filing Requirements for Future GETs Reports – select option 3, and:
- Transparency and Data Access – consider
- Integration into Transmission Planning – consider
- Standardization of Assumptions – consider
- Reporting on Approved Projects – select or write a new option

III. Technologies to be Evaluated
- Maintain Current Scope – select one or more
- Expand Technologies for Evaluation – consider
- Combinations of GETs and Traditional Solutions – consider

IV. Constraints to be Evaluated
- Threshold for Evaluation – select one
- Outage Information – consider
- FTR Binding Constraints

V. Payback Period Methodology
- Overall – select one or more
- Data on Curtailment Payments – consider

VI. Accounting for FTRs
- Calculating the Cost of Congestion – select one or more
- FTR Reporting – consider

VII. Payback Period Threshold
- Technology-Specific Payback Thresholds – select one or more

DECISION OPTIONS

I. Approval of the 2025 GETs Report and Implementation Plan

Select 1 or 2 (inclusive of subpart A)

1. Approve the 2025 Implementation Plan and accept the 2025 GETs Report as complete. (MTO)

OR

2. Approve the 2025 GETs Implementation Plan, and accept the 2025 GETs Report as complete, conditional on provision of the following. (DOC)

    A. Transmission owners shall provide updates every two months in this docket regarding their evaluation of constraints with identified solutions, but for which a payback period was not calculated as of the 2025 GETs Report. Payback period results, and if applicable, implementation plans for these projects, shall be filed when the analysis is complete. (Staff interpretation of DOC)
    MTO: not opposed

II. Filing Requirements for Future GETs Reports

Select 3 or write an alternative

3. Minnesota transmission owners shall publish a GETs Report on a biennial basis aligned with the Biennial Transmission Projects Report. (AMP, CEOs, DOC, MTO, RMEB, WATT)

<u>Transparency and Data Access</u>

Consider any combination of options 4 through 9

4. To improve transparency and enable public review, transmission owners shall limit the use of trade secret designations in future GETs Reports to the greatest possible extent. (CEOs)

5. To improve transparency and enable public review of future GETs Reports, transmission owners shall work to reduce the volume of trade secret designations and/or to publicly publish summary information on the GETs analysis and GETs implementation plan. (Staff option)

6. Transmission owners shall make a Compliance Filing within 30 days of this Order refiling the 2025 GETs Report to disclose any information that was marked as “trade secret” but which can be made public, and noting each change. (Staff interpretation of CEOs)

7. In future GETs Reports, transmission owners shall include work papers, including derivations of all calculations, as a separate appendix attached to the GETs Report. (DOC)
    MTO: no objection

8. In future GETs Reports, transmission owners shall include more data in their work papers, including at least the following data points for each constraint studied, regardless of whether the payback threshold was achieved:
    A. Underlying congestion and GETs modeling assumptions,
    B. Unadjusted congestion charges,
    C. The type of GET(s) that was studied,
    D. Solution(s) costs, and
    E. Calculated project benefits.
    (DOC)

9. In future GETs Reports, transmission owners shall include a summary table of the solutions that meet the appropriate payback period threshold. The table shall contain at minimum each identified solution's name (or that of the congestion point), the solution's cost, the three-year average congestion charge, and the calculated payback period. (DOC)

Integration into Transmission Planning
Consider 13, or any combination of 10, 11 and 12

10. In the next GETs Report, transmission owners shall demonstrate that they have deployed or are prepared to deploy DLR. (WATT)

AND/OR

11. Transmission owners shall develop the internal infrastructure and coordination to facilitate deploying GETs at a programmatic level rather than on a project-by-project basis. As a first step, utilities shall establish the training, processes, and software needed to incorporate GETs technology into all relevant planning, standards, and operations processes. (CEOs)

AND

12. Transmission owners shall incorporate GETs analysis, at minimum for advanced powerflow controllers and topology optimization, into all transmission project development processes as either possible alternatives or supplements during construction. (Staff interpretation of CEOs)

OR

13. In the next GETs Report, each transmission owner shall discuss how their company is working to integrate GETs into planning, project development, standards, and operations. (Staff alternative)

Standardization of Assumptions
Consider 14 and/or 15

14. Transmission owners shall develop a generic cost estimating guide for Grid Enhancing Technologies and file this as an attachment to the 2027 GETs Report. (Staff interpretation of MTO)

AND/OR

15. In future GETs Reports, transmission owners shall use standardized line and facility ratings methodologies and assumptions to facilitate better shared learnings across the different transmission owners and better interoperability between GETs deployments. (CEOs)

Reporting on Approved Projects
Select 16 or write an alternative

16. In future GETs Report, transmission owners shall include:
    A. A discussion of each approved project, observations of the congestion impact or other results after implementation, and lessons learned.
    B. A table or attachment listing for each of the approved GETs Report projects:
        - Name of project
        - Approval year
        - Transmission owners
        - High-level summary of technology being deployed
        - Project status and estimated or actual in-service date
        - Estimated cost at time of approval
        - Actual cost
        - Calculated three-year average congestion charge at time of approval
        - For projects in service for 12 months or more: Congestion charge based on the year after implementation

    (Staff option)

III. Technologies to be Evaluated

Maintain Current Scope
Select 17 and/or 18

17. In the next GETs Report, transmission owners shall provide complete feasibility and payback period analyses for all identified transmission constraints, and complete implementation plan details as applicable. (DOC, CEOs, WATT)

AND/OR

18. In the next GETs Report, transmission owners shall focus on DLR, APFC, and TTO technologies. (WATT)

Expand Technologies for Evaluation
Consider adopting 19, 20, or 21. Any combination of 22, 23, 24 may be selected as well.

19. In future GETs Reports, transmission owners shall include a discussion of new, emerging, and underutilized (but currently commercially viable) GETs, as well as the possibility of developing GETs pilot projects with vendors. (DOC)

OR

20. In future GETs Reports, transmission owners shall include a discussion of trends and general developments in GETs technologies as they relate to system planning and operations. (MTO)

OR

21. In future GETs Reports, transmission owners shall include the following:
    A. A summary of grid enhancing technologies available and in development,
    B. A summary of each technologies' commercial readiness and how it is being deployed,
    C. A summary of each transmission owners' GETs deployment efforts and results to date,
    D. A discussion of whether each transmission owner has studied or is considering any advanced transmission technologies,
    E. A discussion of research collaboratives transmission owners may participate in,
    F. What transmission owners see as being the best use cases and/or nearest-term opportunities for GETs and advanced transmission technologies on their systems.

    (Staff alternative)

AND/OR

22. In future GETs Reports, transmission owners shall consider reconductoring with High Performance Conductors (HPCs) among the GETs evaluated. (AMP, RMEB)

AND/OR

23. Transmission owners shall consult with high performance conductor technology vendors during development of future GETs Reports. (AMP)

AND/OR

24. In future BTPR and GETs Reports, transmission owners shall systemically consider advanced

transmission technologies (ATTs) among alternatives studied to address inadequacies or constraints. Transmission owners shall attach to the BTPR and/or GETs Report any technical studies performed for these evaluations. ATTs include at minimum:

A. Reconductoring with advanced conductors
B. Storage as a grid asset or storage as a transmission-only asset

(CEOs, RMEB)

Combinations of GETs and Traditional Solutions
Consider 25 or 26. 27 may be selected with either.

25. In future GETs reports, transmission owners shall consider adding GETs to any proposed traditional upgrades where feasible and where costs would not significantly increase. (DOC)

OR

26. Where feasible and where costs would not significantly increase, transmission owners shall consider adding GETs to any proposed traditional upgrades. This analysis shall occur in relevant certificate of need proceedings. (MTO)

AND/OR

27. AAR deployments are not eligible to be included in implementation plans in future GETs reports. (DOC)

IV. Constraints to be Evaluated

Threshold for Evaluation
Select between 28 or 29. 29 can be adopted in whole, or one subpart may be chosen.

28. In the 2027 GETs Report, transmission owners shall continue to evaluate GETs and traditional solutions for constraints that have experienced 168 hours or more of congestion in any of the past three years.

OR

29. In future GETs Reports, transmission owners shall evaluate GETs solutions for constraints that had 168 hours or more of congestion in any of the past three years as well as for locations that are expected to have high levels of congestion in future years due to:
    A. Construction or planned outages (DOC, CEOs, WATT, RMEB) **and/or**
    B. Congestion is indicated by modeling (WATT, CEOs, RMEB)

Outage Information
Consider 30 and/or 31.

30. In future GETs Reports, transmission owners shall discuss recent congestion studies performed by MISO, identify whether any locations identified by MISO are also identified as having high levels of congestion in the GETs Report, and describe actions transmission owners are taking to address congestion in areas identified by MISO. (Staff interpretation of WATT)

AND/OR

31. In future GETs Reports, for constraints driven by outages, transmission owners shall identify the expected duration and end date of the outage. (Staff interpretation of WATT)

FTR Binding Constraints
Consider 32 or 33.

32. In future GETs Reports, transmission owners shall consider constraints identified in the FTR binding constraint list published by MISO, in addition to the data sources used in the 2025 GETs Report to identify potential opportunities for GETs implementation. (DOC)

OR

33. In the 2027 GETs Report, transmission owners shall discuss whether and how they could include evaluations of GETs to alleviate FTR binding constraints in future GETs Reports. Transmission owners shall address the relationship between FTR binding constraints and high-congestion constraints (those with at least 168 hours of congestion per year), explain in general the potential for GETs and ATTs to mitigate FTR binding constraints, and discuss how it could use, and prioritize within, binding constraint lists to identify high-value locations for evaluation of potential GETs deployments. (Staff alternative)

V. Payback Period Methodology

Overall
Select one from 34, 35, or 36. The Commission may choose 37 and/or 38(A or B) if desired.

34. In the 2027 GETs Report, transmission owners shall continue to utilize the cost-benefit framework developed in Docket No. E999/M-25-99 when evaluating GETs proposals brought forward by individual utilities. (MTO)

OR

35. In future GETs Reports, transmission owners shall calculate the payback period of potential

GETs deployments using a broader range of benefits and costs that result from physically addressing the congestion. (Staff interpretation of DOC, CEOs, RMEB)

OR

36. In future GETs Reports, transmission owners shall include potential losses or gains to county and municipal tax revenue in the payback period calculation for potential congestion mitigations. (RMEB)

AND/OR

37. In the 2027 GETs Report, transmission owners shall discuss whether and how they could include additional metrics in the payback period calculation for GETs to achieve a more comprehensive and accurate result. The Report shall discuss at minimum the following potential additional metrics:
    A. the value of avoiding replacement energy purchases,
    B. the value of avoiding curtailment payments, and
    C. the value of improved renewable energy deliverability.

    (Staff alternative)

AND/OR

38. Transmission owners shall file for informational purposes payback period calculations for the constraints identified in the 2025 GETs Report, using a broader range of benefits and costs that would result from physically addressing the congestion. (DOC)
    A. As part of the 2027 GETs Report (Staff option)
    B. By October 1, 2026 (Staff option)

<u>Data on Curtailment Payments</u>
Consider 39.

39. In future GETs Reports, transmission owners shall provide any information they have about PPAs or curtailment payments to generators on transmission lines where they also hold FTRs, as well as replacement energy purchases. (DOC)

VI. Accounting for FTRs

<u>Calculating the Cost of Congestion</u>
Select between 40 and 42. If the Commission selects 40, it may also select 41.

40. In future GETs Reports, transmission owners shall continue to net FTR profits from the congestion charge for purposes of the payback period calculation. (DOC, MTO)

AND

41. In future GETs Reports, transmission owners shall provide the congestion charge and payback period for each applicable constraint without FTR adjustment for informational purposes. (MTO)

OR

42. In future GETs Reports, transmission owners shall not include Financial Transmission Rights (FTR) revenues when calculating the cost effectiveness of potential GETs deployments. (WATT)

FTR Reporting
Consider 43 and/or 44.

43. In future GETs Reports, transmission owners shall include work papers showing both FTR charges and revenues, not just net revenues. (Staff Interpretation of DOC)

AND/OR

44. In future GETs Reports, transmission owners shall include separate attachments showing adjusted congestion charges for each constraint, a) when considering FTRs held by Minnesota transmission owners and b) when considering FTRs held by all MISO market participants. (Staff interpretation of DOC)

VII. Payback Period Threshold

Technology-Specific Payback Thresholds
Select between 45, 46 and 47, or 48. Subpart A may be selected with 45.

45. In future GETs Reports, transmission owners shall use a payback period threshold appropriate to each specific technology type and shall provide a cost estimate and implementation schedule for each GETs deployment that meets the technology-appropriate threshold. (DOC, AMP)

    A. Transmission owners shall include a comprehensive explanation of how they arrived at each technology-appropriate threshold. (Staff option)

OR

46. Delegate authority to the Executive Secretary to open a comment period to establish technology-specific payback period thresholds for each GET technology type including, but not limited to, dynamic line rating, power flow control, topology optimization, and advanced

reconductoring. (DOC, AMP)

AND

47. MTO to provide cost estimates and implementation schedules for GETs solutions using the technology-appropriate payback period threshold. (DOC, AMP)

OR

48. In future GETs Reports, transmission owners shall continue to use a five-year payback period threshold.