MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**July 1, 2025**	**Agenda Item **5B**
Company	Minnesota Transmission Owners	
Docket No.	**E999/M-25-99**	
	In the Matter of the 2025 Biennial Transmission Projects Report	

Issues

- What methodology should the Commission direct affected transmission owners to use in calculating the payback period of grid enhancing technologies (GETs) as directed by Minnesota Session Laws, 2024, Chapter 127, Article 42, Section 52?
- What payback period *value* should the Commission set as the threshold at which a GETs project must be included in the implementation plan portion of a transmission owner's GETs Report?
- Should the Commission request or require transmission owners to evaluate the cost effectiveness or payback periods of GETs projects addressing locations likely to experience high levels of congestion during the next five years (Subd. 2, clause 3), in addition to those with existing congestion (Subd. 2, clause 1)?

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✓**Relevant Documents**	**Date**
Minnesota Transmission Owners – Comments	April 11, 2025
Department of Commerce – Comments	April 11, 2025
EDF Renewables – Comments	April 11, 2025
WATT Coalition – Comments	April 11, 2025
Minnesota Transmission Owners – Reply Comments	May 9, 2025
WATT Coalition – Reply Comments	May 9, 2025

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ACRONYMS

AAR: Ambient Adjusted Ratings
ANOPR: Advanced Notice of Proposed Rulemaking
APC: Adjusted Production Cost
DOC: Department of Commerce
DOE: U.S. Department of Energy
DLR: Dynamic Line Rating
DTR: Dynamic Transformer Rating
FERC: Federal Energy Regulatory Commission
GETs: grid enhancing technologies
INL: Idaho National Laboratory
ISO: Independent System Operator
LRTP: Long Range Transmission Planning
LRZ: Local Resource Zone
MISO: Midcontinent Independent System Operator
PFC: Power Flow Controller
RTO: Regional Transmission Organization
TO: Topology Optimization

STATEMENT OF THE ISSUES

There are four primary questions that require the Commission's attention in this proceeding:

1. What methodology should the Commission direct affected transmission owners to use in calculating the payback period of grid enhancing technologies (GETs) as directed by Minnesota Session Laws, 2024, Chapter 127, Article 42, Section 52?
2. What payback period *value* should the Commission set as the threshold at which a GETs project must be included in the implementation plan portion of a transmission owner's GETs Report?
3. Should the Commission request or require transmission owners to evaluate the cost effectiveness or payback periods of GETs projects addressing locations likely to experience high levels of congestion during the next five years (Subd. 2, clause 3), in addition to those with existing congestion (Subd. 2, clause 1)?
4. Are there equity, workforce, or environmental justice factors the Commission should consider in establishing a GETs payback period methodology?

BACKGROUND

I. Implementation of the 2024 GETs Law

The purpose of this proceeding is to establish a payback period calculation methodology to be used in evaluating grid enhancing technologies ("GETs") as required by Minnesota Session Laws, 2024, Chapter 127, Article 42, Section 52 ("2024 GETs Law").

The 2024 GETs Law defines "grid enhancing technology" as follows:

> "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.[1]

Under Minn. Stat. § 216B.2425, utilities and companies that own or operate electric transmission lines in Minnesota ("Minnesota Transmission Owners") are required to file biennial transmission project reports (BTPRs), which must identify transmission system inadequacies and solutions to them.[2] Laws of Minn. 2024, Ch. 127, Article 42, Sections 19, 20, and 21 amended this section to require that going forward, these reports will consider GETs

[1] Minnesota Session Laws, 2024, Chapter 127, Article 42, Section 52, Subd 1(e) Available at: https://www.revisor.mn.gov/laws/2024/0/Session+Law/Chapter/127/

[2] Minn. Stat. §216B.2425, Subd. 2

among the alternative means of addressing identified transmission system inadequacies.[3]

Section 52 (i.e., the 2024 GETs Law) additionally 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 the feasibility of GETs to address each instance of grid congestion. 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.[4] In the remainder of this Briefing Paper, Staff refers to the specific GETs evaluation required this November as the 2025 GETs Report. This report will be part of 2025 BTPRs.

2025 GETs Reports must analyze the cost-effectiveness of using GETs to mitigate congestion at the identified locations, calculate the payback period of each GETs installation using a methodology developed by the Commission, and include projects that meet a payback period threshold determined by the Commission in an implementation plan. The relevant section is excerpted below, and the full text of this 2024 Session Law is included as Attachment 1 to these Briefing Papers.

> **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

[3] 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/

[4] Minnesota Transmission Owners, Comments, Docket No. E999/TL-01-961, July 30, 2001, at 1

commission, in order to maximize transmission system capacity; and
(7) explains the transmission owner's current line rating methodology.[5]

Subd. 3 requires that the Commission must review, and may approve, reject, or modify each GETs implementation plan submitted pursuant to Subd. 2 (shown above). Within 90 days of an Order approving elements of an implementation plan, public utilities must file a workplan, cost estimate, and schedule to implement approved elements located in their service territory.

The Commission initiated the instant proceeding in order to achieve the following steps before affected transmission owners submit GETs reports on November 1, 2025:

- Approve a methodology for calculating the payback period of GETs applications, as required by Subd. 2, part (5).
- Identify the payback period value at which a GETs project must be included in the implementation plan portion of the GETs Report, as required by Subd. 2, part (6).
- Determine whether it is appropriate for transmission owners to evaluate the cost-effectiveness of GETs in addressing instances of likely future congestion, as identified under Subd. 2 clause (3), in addition to instances of existing congestion identified under Subd. 2 clause (1).

II. Grid Enhancing Technologies

The 2024 GETs Law defines GETs and provides three examples of technologies that qualify as GETs: dynamic line rating, advanced power flow controllers, and topology optimization. To aid the Commission in its decision-making process, Staff provides a brief summary of how each of these technologies works, as well as for two other related technologies that are discussed in this record – ambient adjusted ratings (AAR) and dynamic transformer ratings (DTR). 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:[6]

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.

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[5] Minnesota 2024 Session Laws, Chapter 127, Article 42, Section 52

[6] 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

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).

Power Flow Controller (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.

Topology Optimization (TO): Using 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.

III. Related Federal Regulatory Actions

There are at least two regulatory actions by the Federal Energy Regulatory Commission (FERC) that will affect transmission owners' implementation of GETs in the coming years, and which may be relevant to the Commission's decision in this matter and future decisions in this docket.

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.[7] MISO submitted proposed tariff revisions to FERC to comply with this order in July 2022, requesting an effective date in July 2025. However, in March 2025, MISO requested a more than three-year extension until December 31, 2028. The Independent Market Monitor, the Organization of MISO States, and others have requested FERC reject or significantly limit the proposed extension,[8] arguing that a faster implementation of AAR will provide significant ratepayer savings, enable interconnection of more generation capacity, and improve reliability.

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

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

[8] Comments of Potomac Economics, Ltd., April 22, 2024, FERC Docket No. ER22-2363-002; Answer of the Organization of MISO States, Inc., April 21, 2024, FERC Docket No. ER22-2363-002, available here: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250421-5191

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.[9]

Party positions on the impact these FERC proceedings should have the Commission's decision in this matter are discussed in Part II.D.

PROCEDURAL HISTORY

The Commission's *Notice of Comment Period* in this record contained the following questions:

- In addition to the frequency of congestion and increased costs to ratepayers (as required by Subd 2, clause 2), what, if any, issues, costs, and benefits are relevant to calculating the payback period of GETs installed to reduce transmission system congestion?
- What methodology should the Commission direct affected transmission owners to use in calculating the payback period of GETs in reducing congestion?
- What payback period value should the Commission set as the threshold at which a GETs project must be included in the implementation plan portion of a GETs Report?
- Should the Commission request or require transmission owners to evaluate the cost effectiveness or payback periods of GETs projects addressing locations likely to experience high levels of congestion during the next five years (Subd. 2, clause 3), in addition to those with existing congestion (Subd. 2, clause 1)?
- Are there equity, workforce, or environmental justice factors the Commission should consider when developing a GETs payback period methodology?
- Are there other issues or concerns related to this matter?

On April 11, 2025 the following parties submitted Initial Comments:

- Minnesota Transmission Owners (MTO) – a group including 14 investor-owned, municipal and cooperative utilities that own and operate high voltage transmission lines in Minnesota and together file the biennial transmission report due by November 1 each odd numbered year pursuant to Minn. Stat. § 216B.2425.

- The Department of Commerce, Division of Energy Resources (the Department or DOC) – the state agency tasked with providing objective analysis and advocating for the public interest in proceedings before the PUC.

- EDF Renewables (EDFR) – an independent power producer that develops, owns, and operates renewable energy projects. EDFR notes that it has experience with GETs in other markets.

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[9] 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

- Working for Advanced Transmission Technologies (WATT) Coalition - a trade association focused on facilitating the adoption of advanced transmission technologies in the U.S. WATT notes that its members include, among others, transmission owners and technology vendors with expertise in PFD, DLR, and TO.

On May 9, 2025, MTO and WATT submitted Reply Comments. Party positions are summarized in the following section, organized by topic.

PARTY POSITIONS

I. GETS PAYBACK PERIOD METHODOLOGY

In this section, Staff summarize party positions on how best to calculate the payback period of potential GETs solutions, including: (A) the costs and benefits that are relevant to the calculation, (B) methods for quantifying the cost of congestion, (C) methods for assessing cost effectiveness, and (D) methods for setting a threshold value for project inclusion in GETs implementation plans.

A. COSTS AND BENEFITS TO CONSIDER

Parties discussed myriad costs and benefits relevant to evaluating the payback period or cost effectiveness of a GETs deployment. There was general agreement that relevant GETs costs include project-specific capital and O&M costs, and that benefits include lower production costs attributable to relieving congestion. There was more disagreement in the record about benefits factors than cost factors. For brevity, Staff lists the costs and benefits discussed by party in Table 1 below. Note that some of these costs and benefits have overlap, and parties may also agree with factors suggested by others.

Table 1: Consolidated Table of GETs Benefits and Costs Discussed by Parties

<table>
<tr><th>Grid Enhancing Technologies Costs</th><th>MTO</th><th>DOC</th><th>EDFR</th><th>WATT</th></tr>
<tr><td>Project capital cost</td><td>✓</td><td>✓</td><td rowspan="8">Not specified</td><td>✓</td></tr>
<tr><td>Project operations and maintenance costs (O&M)</td><td>✓</td><td>✓</td><td>✓</td></tr>
<tr><td>Cost of design work and installation*</td><td>✓</td><td></td><td>✓</td></tr>
<tr><td>Cost of licensing*</td><td>✓</td><td></td><td>✓</td></tr>
<tr><td>Physical and cyber security capital costs*</td><td>✓</td><td></td><td></td></tr>
<tr><td>Physical and cyber security O&M costs*</td><td>✓</td><td></td><td></td></tr>
<tr><td>Cost of outages during construction*</td><td>✓</td><td></td><td></td></tr>
<tr><td>Incremental wear and tear from reconfiguration, if applicable*</td><td></td><td></td><td>✓</td></tr>
<tr><td colspan="5"></td></tr>
<tr><th>Grid Enhancing Technologies Benefits</th><th>MTO</th><th>DOC</th><th>EDFR</th><th>WATT</th></tr>
<tr><td>Avoided costs of energy (e.g., using more wind energy instead of a peaker plant</td><td>✓</td><td></td><td></td><td>✓</td></tr>
</table>

generator)				
Avoided costs of outages	✓		✓	
Ability to serve more load	✓			
Ability to perform maintenance in opportune windows	✓			
Reduced renewable curtailment		✓	✓	✓
Reduced transmission congestion		✓	✓	✓
Reduced price differentials		✓		
New asset deferral		✓		
Improved situational awareness		✓	✓	✓
Resilience and Contingency Support		✓	✓	✓
Asset health monitoring		✓	✓	✓
Reduced cost of new interconnection		✓	✓	✓
Improved transfer capability across regions			✓	✓
Advancing state policy aims			✓	
**Staff note: Some of these costs may be included in project capital or O&M costs, but are noted separately for clarity.*				

1. Costs

As shown in Table 1 above, parties generally agreed that relevant costs include the capital and operation and maintenance (O&M) costs associated with each specific deployment, including hardware, software and licensing costs.[10] The Department specified that capital costs should be quantified using project life, rate of return, tax rates, and other accounting factors.

MTO recommended that capital and O&M for any physical security and cybersecurity protections associated with safely implementing the GET should also be included.[11]

WATT argued that internal work by transmission owners to enable usage of GETs, such as upgrading systems and processes or providing training for employees, is overdue and should *not* be included in the costs of a singular GETs deployment as these types of investments support all future use of GETs. WATT argued that utilities should make such investments proactively.[12]

2. Benefits

Parties were also in agreement that the frequency of congestion and the cost to ratepayers of congestion are key factors in calculating the benefits of GETs and are required by the 2024 GETs Law. All parties also agreed that GETs have additional benefits beyond congestion relief.[13]

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[10] MTO Initial Comments at 2; Department Comments at 3; WATT Initial Comments at 3; EDFR Comments at 2-3.

[11] MTO Initial Comments at 2

[12] WATT Initial Comments at 3

[13] MTO Reply Comments at 2; Department Comments at 2-3; WATT Initial Comments at 2

MTO and the Department provided lists of benefits and costs of GETs discussed in publications from the U.S. Department of Energy and the Idaho National Laboratory.[14] Both EDFR and WATT described a number of GETs benefits, including the ability to monitor asset health (which can provide resilience and reliability benefits), and the ability for GETs to aid in faster and cheaper interconnection of new low-cost generation resources. Additionally, WATT stated that PFC can be deployed to reduce wear and tear on expensive grid assets, while TO can be used to better optimize the entire system under a variety of conditions, which can improve resilience and reliability.[15]

EDFR noted that some GETs may have localized benefits while others have a more regional impact, and recommended the Commission encourage cost effective GETs solutions for both local and regional congestion. Additionally, EDFR emphasized that it expects Minnesota to see congestion and/or renewables curtailment in the coming years related to outages for construction of Long-Range Transmission Planning (LRTP) lines. Both EDFR and WATT asserted that GETs can be effectively deployed to reduce construction-associated congestion costs.[16]

3. Other Considerations

MTO discussed several potential challenges of implementing GETs, which it cautions can reduce a GETs solution's benefits or cause other indirect costs. MTO recommended that these potential costs, listed below, be considered in the cost effectiveness evaluation. WATT responded to these concerns in Reply Comments and agreed that such issues should be taken in account. In general, WATT argued that these costs will not be any larger for GETs than for traditional solutions, and that in some cases can be studied and mitigated.[17] These additional considerations include:

1. **Reduced Line Rating:** There is a possibility that at times dynamic line rating (DLR) can result in line ratings below ambient adjusted ratings (AAR). While DLR generally results in higher line ratings, allowing conductor to carry more power, MTO noted that a study in Massachusetts "found that DLRs can result in line rating below ambient adjusted ratings approximately 22-27 percent of the time throughout the year."[18]

   WATT agreed this can happen in rare instances and should be included in the benefits calculation. Information about lower real-time ratings helps to improve grid reliability by providing a more accurate picture of line capacity and risk profile.

2. **Moving Congestion Elsewhere:** MTO noted that there is potential for GETs to solve congestion in one area, but to push the problem onto another part of the system, which makes a different piece of infrastructure the 'limiting element.' MTO asked that any calculation of costs and benefits consider the costs of a full solution, not just an immediate

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[14] MTO Comments at 2, citing to: https://inl.gov/national-security/grid-enhancing-technologies/

[15] WATT Initial Comments at 3

[16] EDF Comments at 5

[17] WATT Reply Comments at 2-3

[18] MTO Initial Comments at 3

or single fix.

WATT noted this is normal and expected, because grid planning typically seeks to resolve the most limiting constraint first. If that mitigation unlocks more capacity than the next limiting element can transmit, the constraint will move. WATT noted that even when congestion moves, a GETs deployment can be cost-effective – especially if addressing an area with very expensive congestion. WATT recommended that if MTO determines congestion will move, it calculate the cost of addressing that next constraint and assess whether the project is cost effective with (or without) the second mitigation.[19]

3. **Outages and Scheduling Impacts:** MTO noted that with construction beginning on MISO LRTP Tranche 1 lines, the region will have more construction-related outages in the coming years. MTO asserts the potential for increased congestion or related costs during GETs installation is a direct cost that should be considered when evaluating a solution's costs and benefits.

   WATT did not object to including the costs of outages for GETs installation, noting that many GETs do not require significant outages. In fact, WATT stated that some DLR and sensor-based systems can be installed in one day, and that TO does not entail outages as it is entirely software based.[20]

4. **Benefit Relative to Other Solutions:** MTO pointed to existing efforts to reduce congestion on the Minnesota transmission system, including the 2023 Grid North Partners effort, which identified at least 21 projects to increase transmission capacity and reduce congestion. MTO recommended these alternative (likely more "traditional") solutions be considered during the GETs evaluation process to "avoid implementing a GETs solution that provides little to no benefit when viewed in a broader context."[21]

   WATT agreed with MTO that GETs should be evaluated in the context of other planned solutions and views this as an argument in favor of robust analysis of GETs. WATT also noted that in areas where a traditional solution is planned, but several years away from operation, GETs may be able to act as a bridge solution to deliver benefits during planning and construction of larger-scale investments.[22]

   While the Department did not submit Reply Comments, its recommendation that MTO consider GETs in combination with other GETs, with traditional solutions, and compare those options to traditional solutions aimed at addressing this same concern.

5. **Shared Infrastructure:** MTO noted that many substations in Minnesota are shared infrastructure between two or more utilities, which can present challenges for cost recovery and regulatory decisions.

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[19] WATT Reply Comments at 2

[20] WATT Reply Comments at 2

[21] MTO Initial Comments at 4

[22] WATT Reply Comments at 3

WATT noted this issue is not unique to GETs; all transmission planning encounters this complexity. WATT recommended that transmission owners work through MISO to resolve such issues.[23]

6. **<u>Customer Allocation:</u>** Additionally, while not explicitly related to the cost-effectiveness calculation or inputs, MTO recommended the Commission consider which ratepayers will receive the benefits of GETs and which will bear the associated costs and ensure that beneficiaries bear the costs.

4. Staff Analysis

a. Costs and Benefits

Parties recommended many costs and benefits for inclusion in the GETs cost effectiveness calculation. There is a strong consensus around the largest drivers of cost and benefit, though there is some disagreement agreement in the record about how comprehensive the list of included benefits should be.

The Commission has several choices on how to proceed with this element of the record: It could require transmission owners to quantify, to the maximum reasonable extent, a specific list of costs and benefits for each GETs project to be studied **(Decision Option 15).**

If the Commission wishes to provide direction with significant flexibility, it could instead require transmission owners to consider all of the comments received, quantify to the maximum reasonable extent all relevant costs and benefits for each GETs deployment, and provide its rationale as part of the 2025 GETs Report **(Decision Option 16).**

Alternately, the Commission can take no action on this element of the record and instead review the cost effectiveness calculations transmission owners provide in the 2025 GETs Report.

If the Commission wishes to provide transmission owners with specific direction, Staff offers the following comments on the proposed cost and benefits. Staff has no concerns with the cost factors discussed in the record, though several of them (design and installation, software licensing) are commonly included in project capital or O&M costs. The Commission will want to ensure double counting is avoided.

Several of the benefits proposed refer to similar or overlapping topics, so the list may be able to be consolidated. For example, MTO suggested using the avoided cost of energy to value the benefits of using more renewable power instead of peaking plant generation, while other parties suggest three factors (reduced renewable curtailment, reduced transmission congestion, and reduced price differentials) which *may* be included under the avoided cost of energy depending on how this is calculated. Similarly, Staff identified some overlap between

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[23] WATT Reply Comments at 3

the categories improved situation awareness, resilience and contingency support, and asset health monitoring. Finally, the reduced cost of new interconnection and the advancement of state policy aims may benefit from further record development on how to quantify these factors.

b. Other Considerations

Several other considerations MTO mentioned appear to be addressable in a quantifiable way in a cost-effectiveness calculation. For example, the potential for DLR to cause occasional times of reduced line rating, the potential for congestion to move elsewhere, and the costs of outages during installation or construction all appear to Staff to be factors that can be considered when quantifying the costs and benefits of a GETs solution. There was no opposition in the record to considering these costs, though WATT noted that several of them are normal, expected costs of any transmission project.

Staff therefore finds it reasonable for MTO to include these factors, as relevant, in its GETs evaluations. However, in order to avoid double-counting, it would be beneficial for MTO to specify in its 2025 GETs Report when factors are being considered “costs” or are incorporated into the benefits side of the calculation (i.e., to arrive at “net benefits”). Staff offers **Decision Option 2** to direct this reporting:

2. Transmission owners shall provide an explanation of each cost and benefit factor included in GETs cost effectiveness evaluations and provide workpapers showing the cost-effectiveness calculation and how each input was quantified. (Staff Option)

Regarding WATT’s recommendation that transmission owners evaluate the costs of addressing secondary congestion if they identify that a potential GETs deployment will shift congestion to another limiting element **(Decision Option 14)**, Staff understands and appreciates WATT’s rationale. However, it is not clear based on this record how common this issue may be and the scale of potential ratepayer benefits from evaluating secondary GETs mitigations. This issue would benefit from further record development and the Commission could direct evaluation of secondary mitigations in future GETs analyses.

MTO’s concerns about shared infrastructure and customer class allocation are important considerations during cost recovery that do add complexity, but in Staff’s view are issues commonly addressed with transmission projects. Absent more record development about GET-specific complexity, Staff expects that such issues can be worked out through normal transmission project planning and approval processes.

B. PAYBACK PERIOD METHODOLOGY

Parties offered different opinions on how best to evaluate the cost-effectiveness of a GETs project. Both MTO and WATT recommended using a payback period methodology that compared the cost of a GETs deployment to its annual benefits and recommended that the cost of historical congestion be quantified using a congestion charge (or congestion rent) value. As discussed in the following section, WATT recommended evaluating all projects over a 5-year timeframe, while MTO recommended using project-specific payback period thresholds.

In general, a payback period calculation takes the form shown in Figure 1 below, which divides total project cost by annual savings (or benefits) to determine how many years of savings it will take to “payback” the costs.

Figure 1: Generic Payback Period Formula

$$\text{Payback Period (Years)} = \frac{\text{Total Project Costs (\$)}}{\text{Annual Savings (\$/Year)}}$$

However, MTO and WATT disagreed on how the congestion-reducing impact of GETs should be calculated, with WATT recommending PROMOD-based Adjusted Production Cost (“APC”) modeling which uses power flow simulations and production cost modeling of constraints both with and without the potential GETs project in service, over 8760 hours in all relevant years. Comparing results with and without GETs provides an estimate of the production cost savings that would arise from project deployment.[24] MTO suggested APC modeling is problematic because PROMOD cannot always recreate historical congestion and likely results in an underestimate.[25]

The Department suggested using a benefit-cost ratio (BCR) methodology instead of a payback period, but did not explicitly recommend approving a BCR method. However, the Department recommended specific BCR ratios be used as thresholds for inclusion in the proposed GETs implementation plan. A BCR generally takes the form show in Figure 2 below.

Figure 2: Generic Cost Benefit Ratio Formula

$$\text{Benefit-Cost Ratio} = \frac{\text{NPV Total Project Benefits (\$)}}{\text{NPV Total Project Costs (\$)}}$$

EDFR did not make a specific recommendation on methodology but encouraged the Commission to prioritize flexibility in whatever method it approves. EDFR noted that BCR is a well-known and documented framework, which provides some advantages, but stated also that congestion charges and APC metrics, are also commonly used in transmission planning. However, EDFR cautioned that on its own, an APC assessment is likely to be a conservative estimate of a GETs solution’s benefits.[26]

Each of the proposed methods is described below.

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24 MTO Initial Comments at 5; WATT Initial Comments at 5

25 MTO Initial Comments at 5, MTO Reply Comments at 6

26 EDFR Comments at 4

1. Congestion Charge Method

All parties agreed that the value of avoided congestion will be a primary factor in the cost-effectiveness evaluation, and Staff notes that transmission owners are required to calculate this figure under Subd. 2, clause (2) which states the 2025 GETs Report must include information that "estimates the frequency of congestion at each location and the increased cost to ratepayers resulting from the substitution of higher-priced electricity." Subd. 2, clause (5) then requires that the GETs cost effectiveness evaluation incorporate the cost to ratepayers calculated under clause (2).

MTO offered two options for quantifying the costs to ratepayers of each instance of congestion, which would inform the benefits side of the GETs payback period calculation:

1. **Shadow price** – the incremental cost saving associated with relieving a binding constraint by 1MW, resulting in a dollar-per-MW value.

2. **Congestion Charge** – the shadow price of a constraint ($/MW), multiplied by the full rating of the constraint (MW), resulting in a dollar value.

A shadow price reflects the value of 1 MW worth of congestion relief – e.g., if a constraint binds at 100 MW, the shadow price reflects the congestion benefit of raising the rating to 101 MW. MTO explained that shadow price is a commonly used metric reported by PROMOD, and that transmission owners "commonly sum up the hourly shadow prices per constraint to get an annual total, then compare shadow prices of different constraints to assess the severity of each."[27]

As shadow price only reflects 1 MW, it does not reflect the actual value of *fixing* a constraint. To calculate that, MTO would use PROMOD to model a utility's load costs and generation revenues both before and after the solution is implemented in the model. MTO noted that this method would require recreating historical congestion in the model, which is prone to inaccuracy.[28]

MTO prefers using its second method (congestion charge) to quantify the benefits of a GET solution because it would avoid needing to rely on PROMOD to replicate historical constraints. MTO did note however, that this method may overstate congestion costs (and the value of relieving congestion) by assessing the shadow price to the *full rating* of the line or other limiting element.

Staff's understanding is that under MTO's proposal, hourly shadow prices for each constraint would be summed to provide an annual shadow price, which would then be multiplied by the full rating of the constraint to provide an annual congestion charge. The annual congestion charge for each location of historical congestion would be one component of GETs project benefits. The congestion charge and other quantifiable benefits of each potential GETs project would be compared to the total cost calculated for the project, and MTO would evaluate how

[27] MTO Initial Comments at 5

[28] MTO Initial Comments at 5

long it would take for the potential investment to pay back.

2. Congestion Charge Plus APC Method

WATT recommended evaluating all projects over a five-year timeframe to determine whether a GETs deployment's benefits would payback within five years. WATT also recommended distinct approaches for quantifying the benefits of mitigating historical congestion versus forecasted congestion. WATT agreed with MTO that the savings associated with mitigating known areas of congestion should be quantified using a congestion charge calculation (multiplying the shadow price by the power flow or equipment limit), which WATT referred to as "congestion rent." WATT noted that this is not a precise measure of consumer savings but is the most feasible and representative dataset available.[29]

To quantify the benefit of avoiding *forecasted* congestion, WATT recommended using APC modeling over a five-year future window *or* the duration of the constraint, if a particular constraint is anticipated to be longer than five years.[30]

WATT recommended a two-step process be used to calculate the cost of congestion and the potential impact of GETs on that congestion.[31] At a high level, this entails:

Step 1: Quantify both known and forecasted congestion

- For historical congestion: calculate the congestion charge (congestion rent) for each location of congestion identified during the past three years.
- For forecasted congestion: Use APC modeling to assess the impacts of planned outages during the next five years on power flows, and then use production cost modeling over the duration of these outages to estimate costs.

Step 2: Estimate how much of identified congestion GETs could relieve based on production cost modeling and weather inputs.

- Conduct power flow simulations and production cost modeling over 8760 hours in all relevant years for each constraint being studied. Compare results with and without GETs in-service to estimate the total likely cost savings.
- Use sensitivity analysis to account for uncertainty in commodity prices, weather, real-world conditions, or other factors that may influence cost effectiveness.
- Consult with vendors and other stakeholders during the modeling process to ensure that modeling best practices are considered and that the modeling reflects likely outcomes.

MTO found the recommendation to use APC modeling to be "problematic," noting that PROMOD modeling tools have challenges replicating historical constraints.[32] MTO pointed to MISO's 2023 Transmission Expansion Plan (MTEP23) Report and an October 2023 Planning

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[29] WATT Reply Comments at 3

[30] WATT Initial Comments at 4

[31] WATT Initial Comments at 4-5

[32] MTO Reply Comments at 6

Advisory Committee (PAC) presentation, which both noted that MISO's planning process, including the use of APC, is geared toward long-term planning horizons rather than near-term horizons. The PAC presentation stated that "[h]istoric day ahead congestion cost does not perfectly translate to MISO APC savings in economic models" and lists the following factors which contribute to this mismatch: "generation and transmission outages in real time, transmission system upgrades, and generator additions and retirements."[33]

WATT conceded that modeled APC savings are likely a conservative estimate but asserted that APC modeling is the best option for evaluating forward-looking congestion. WATT also noted that Minnesota utilities have used forward-looking congestion values to inform Grid North Partners transmission planning, which may have used APC. WATT asserted that if APC savings are sufficient to support a major capital project, they should be sufficient to support GETs solutions, which tend to be lower cost.[34]

WATT also cited the MISO 2024 Near-Term Congestion Study Report[35] which used APC modeling to estimate the costs of outages for LRTP Tranche I construction under various scenarios, including estimating the costs of 6-month and 12-month delays to each construction timeline.

3. Benefit-Cost Ratio Method

The Department took issue with using the term "payback period" to assess the value of GETs. As the Department described, a payback period identifies how quickly revenues (or savings) from an investment will offset the costs of the investment – for example, a $5 lightbulb which saves $1 per year in electricity costs has a payback period of 5 years.[36]

The Department asserted this concept is not a relevant way to assess utility capital investments because ratepayers do not pay for an investment upfront, but "pay the cost of the project over a number of years, the duration of which reflects the life of the project" and '[t]he actual cost paid by ratepayers could vary widely depending on the expected life of the projects, rate of return, and several other factors."[37] As a result, the Department is not certain how to calculate a technically valid payback period.

Instead, the Department suggested that a BCR methodology would be a valid way to compare costs and benefits and could be developed using the net present value of ratepayer costs and net present value of ratepayer benefits (i.e., using the costs and benefits identified in Section II.A.). However, the Department did not explicitly recommend that the Commission approve a BCR methodology.

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[33] MISO *Update on MTEP23 Near-Term Congestion Study*, Presentation to the Planning Advisory Committee, October 13, 2023, Slide 3 (Attachment B to MTO Reply Comments)

[34] WATT Reply Comments at 4

[35] MISO, 2024 Near-Term Congestion Study Report, October 2024, https://cdn.misoenergy.org/MTEP24%20Near-Term%20Congestion%20Study%20Report657728.pdf

[36] Department Comments at 3

[37] Department Comments at 3

MTO acknowledged that a BCR provides helpful insights into the cost-effectiveness of a project, but in its view is a limited or narrow metric. According to MTO, a well-informed decision-making process will "incorporate concepts such as BCR along with other analyses like Net Present Value (NPV) and Internal Rate of Return (IRR), as well as considering factors like risk, strategic alignment, and stakeholder perspectives."[38]

4. Staff Analysis

Subd. 2, clause (5) of the 2024 GETs Law specifies that transmission owners must "calculate the payback period of each installation, using a methodology developed by the Commission."[39] Therefore, Staff recommends that the Commission affirmatively approve using a payback period calculation by selecting **Decision Option 1**.

The Commission does not necessarily need to specify how specific inputs to this methodology are calculated, though both MTO and WATT have recommended the Commission do so (**Decision Options 3B and/or 4**). In Staff's view, providing such direction (i.e., by directing use of either MTO's or WATT's approach) would be helpful to reduce the number of contested issues in the 2025 GETs Report.

The Department suggested that using a BCR would be preferable to using payback period, but perhaps in recognition that the 2024 GETs Law directs a methodology focused on payback period, the Department did not advocate for a decision option to use BCR as the approved GETs evaluation methodology. However, the Department's recommendation on *threshold value* for inclusion in the GETs Implementation Plan (discussed in Part I.C. below) uses the BCR method.

Of the two methods recommended by parties, WATT described a payback period calculation and how inputs would be developed most clearly. MTO's proposal did not provide details on how project costs and benefits should be compared, but Staff understands MTO's proposal as a payback period calculation that would follow the general formula shown in Figure 1, with annual savings valued using the sum of hourly shadow prices over one year, multiplied by the equipment rating to provide an annual congestion charge for each location.

To aid the Commission's decision, Staff summarizes the methodologies proposed by MTO and WATT in Table 3 below. In Staff's view, either of these methods are feasible and will provide information on the relative cost-effectiveness of potential GETs projects.

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38 MTO Reply Comments at 3

39 Minnesota Session Laws, 2024, Chapter 127, Article 42, Section 52, Subd 2, clause (5) Available at: https://www.revisor.mn.gov/laws/2024/0/Session+Law/Chapter/127/

Table 3: Summary of Proposed Methodologies

	MTO	WATT
Cost-Effectiveness Evaluation method	Payback Period	Payback Period
Method for calculating savings from mitigating known/ historical congestion	Congestion Charge	Congestion Charge
Method for calculating cost of future congestion	N/A – do not include future congestion	Adjusted Production Cost
Method for calculating savings from mitigating future congestion	N/A – do not include future congestion	Adjusted Production Cost

The Commission should consider several factors when deciding what methodology to approve for transmission owner use in the 2025 GETs Report, including:

- Consistency with the 2025 GETs Law
- Usefulness and accuracy in assessing an individual project's cost-effectiveness
- Usefulness and accuracy in comparing cost-effectiveness across multiple projects
- Clarity and transparency for stakeholders and regulators

Staff evaluates the proposed methodologies on these factors below.

<u>MTO: Payback Period Using Congestion Charge</u>

- Consistent with the 2024 GETs Law.
- May over-estimate benefits of a GETs project by using a congestion charge, which assesses the shadow price of a constraint to the full rating of the limiting element.
- Does not appear to consider the degree of reduction in congestion attributable to a specific GETs project.
- Transparent and relatively simple to replicate the calculation, aside from deriving the shadow price.

MTO's methodology is the simpler of the two options, which has advantages for stakeholder review and ease of comparing various options. It is closely aligned with the language and requirements of the 2024 GETs Law, though Staff notes that the details of how MTO intends to calculate payback are yet to be developed. If the Commission agrees with MTO's recommendation, it can adopt **Decision Option 1** (payback period method) and **Decision Option 3B** (use of congestion charge).

Staff's primary concern with MTO's methodology is that it does not appear to consider the reduction in congestion attributable to the specific GETs project being studied. In other words, in MTO's approach, congestion savings are determined by the shadow price and equipment rating, which are largely independent of the degree to which the GETs project reduces congestion. Staff is therefore uncertain how accurate the results of MTO's calculation would be, and whether the method could unintentionally exclude cost-effective projects in favor of less-effective projects at areas of very expensive congestion.

That said, and as noted throughout these Briefing Papers, the 2025 GETs Report will be the first time that stakeholders and the Commission are reviewing cost effectiveness analyses for GETs projects in a comprehensive way. Staff sees value in simplicity and a method that allows MTO to focus on priority projects. While the 2024 GETs Law requires a one-time GETs Report, other sections of 2024 Session Laws require that transmission owners continue to evaluate GETs among the alternative means of addressing identified transmission system inadequacies.[40] Therefore, the Commission will have opportunities to direct future improvements or changes to how transmission owners evaluate GETs, if it finds there is a public interest in doing so.

WATT: Payback Period Using Congestion Charge and APC

- Consistent with the 2024 GETs Law.
- For known locations of congestion, does not specify how congestion charge, which is an absolute value, will be translated into an *annual savings* value, which is necessary to calculate a payback period.
- May under-estimate the locations and costs of forecasted congestion by using APC, which often forecasts a small percentage of actual, observed congestion.
- Attempted to quantify the avoided future congestion attributable to each GETs project, though may under-estimate savings due to use of APC modeling.
- Clear payback period formula but involves complex modeling to develop the inputs.

At a high level, WATT's method is a straightforward payback period test and has the advantage of quantifying reductions in wholesale power costs attributable to each GETs deployed. However, MTO raised concerns about the accuracy of APC modeling, which is a central input to WATT's methodology. Staff notes that MTO's primary concern with APC modeling appears to be that it underestimates the cost and instances of congestion, which may mean that projects passing WATT's test are likely to be more cost-effective than they appear. There also may be methods for adjusting (or benchmarking) APC results to better reflect historical actuals.

MISO's 2024 Near-Term Congestion Study Report used APC modeling to compare several LRTP Tranche 1 construction outage scenarios and to quantify the cost of 6-month or 12-month delays. However, MISO uses APC modeling to evaluate cost impacts at a regional scale and compares costs at the Local Resource Zone (LRZ) level, and for some specific flowgates (i.e., locations on the transmission system) using "congestion measure." Congestion measure is calculated by multiplying the average annual shadow price ($/MW/hr) of a transmission constraint by the number of annual binding hours (hr/yr).[41] No party has recommended use of "congestion measure" as a metric in this proceeding.

From Staff's review of the record and cited MISO reports, it appears that APC modeling is a commonly used tool for assessing long-term and portfolio-level congestion. The uncertainties in APC modeling mean that this technique may be less reliable for assessing the absolute cost or savings of an *individual* project, but likely would be an effective tool for comparing the *relative* effectiveness of multiple GETs projects.

[40] Minnesota 2024 Session Laws, Chapter 127, Article 42, Sections 19, 20 and 21.

[41] MISO, 2024 Near-Term Congestion Study Report, October 2024 at 16-20, https://cdn.misoenergy.org/MTEP24%20Near-Term%20Congestion%20Study%20Report657728.pdf

If the Commission finds that APC modeling is reasonably accurate and reliable for the purposes of evaluating the effectiveness of GETs projects for the 2025 GETs Report, WATT's method may be the most useful in assessing project cost-effectiveness due to quantifying the savings attributable to a specific deployment. The Commission can adopt WATT's methodology through **Decision Option 1** (payback period method) and **Decision Options 3B and 4** (use of congestion charge and APC modeling).

WATT also recommended that transmission owners consult with GETs vendors and other stakeholders during the modeling process to ensure that modeling best practices are considered and applied as appropriate, and that modeling results reflect probable and realistic outcomes (**Decision Option 18**). Staff believes it would be beneficial to direct MTO to take this step if the Commission orders use of APC modeling.

If the Commission is concerned that APC modeling does not produce reliable results or is otherwise not appropriate for the purposes of this proceeding, it should select MTO's method. If the Commission would like further record development on the accuracy and applicability of APC modeling to inform future GETs reporting, Staff recommends adopting the following reporting requirements, **Decision Option 11**, which are further discussed in Part I.D.4.

11. In the 2025 GETs Report, transmission owners shall provide information on the capabilities and limitations of modeling and forecasting congestion, including APC modeling. Transmission owners shall discuss:
    A. An overview of the most common approaches used to evaluate current and future congestion, and the use cases or applications of each.
    B. An explanation of each step in APC modeling and a description of the modeling tools used.
    C. The level of accuracy of APC and other relevant modeling approaches in forecasting future locations of congestion, the frequency of future congestion, and the cost of future congestion.
    D. Best practices for minimizing uncertainty or the risks associated with uncertainty, including through benchmarking modeling results using historical data.
    E. An example APC calculation for at least two different locations with high congestion, illustrating how APC would be used to quantify the cost of future congestion and savings attributable to a potential GETs deployment.

    (Staff Option)

C. THRESHOLD VALUE FOR INCLUSION IN THE GET IMPLEMENTATION PLAN

Subd. 2, clause (6) of the 2024 GETs Law requires that transmission owners provide "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."

Parties recommended different approaches to establishing this threshold value:

- MTO recommended flexibility so that the threshold reflects the specific technology and application.
- WATT recommended a payback period of five years.
- DOC recommended specific BCR values for the four categories of GETs identified in statute.

1. Flexible Approach

MTO recommended that the Commission offer flexibility and not set threshold values at this time. According to MTO, the threshold for inclusion in the implementation plan should be on a gradient scale to reflect the specific technology and application of each GET. MTO noted that some GETs, such as DLR may have payback periods that are quite short – and almost immediate. Other GETs may have a longer payback period, especially capital-intensive projects like batteries. For these technologies, MTO finds it reasonable for the threshold to be set at or near the expected life of the project.[42]

EDFR also recommended flexibility and did not provide a specific recommendation on the threshold value the Commission should set, but pointed to reports from Brattle and DOE that state GETs investments often pay off within 1-3 years of deployment, with some GETs investments paying off in less than one year.[43]

2. Five-Year Payback Period

As mentioned above, WATT recommended that the Commission use a five-year payback window to determine whether a potential GET deployment is cost effective. However, for locations where congestion is expected to continue past five years, WATT recommended the payback window be set at the duration of expected congestion. Under this approach, if anticipated production cost savings (identified through the APC process) exceed the cost of a GETs deployment within the period evaluated, the GET would move into the planning phase.[44]

WATT asserted that this "simple universal threshold is the most transparent approach to implementing the statute," and that "setting a higher bar by requiring projects to pay for themselves within five years will help focus attention on high-value, near-term deployments."[45]

3. Specific BCR Values

As noted in Part I.B, the Department prefers using a BCR method to assess the cost effectiveness of GETs projects, but did not explicitly recommend the Commission approve this method. However, the Department did recommend the Commission direct the use of BCR values to determine which GETs projects are included in implementation plans.

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[42] MTO Initial Comments at 6; Reply Comments at 2

[43] EDFR Initial Comments at 4

[44] WATT Initial Comments at 6

[45] WATT Reply Comments at 4

The Department asserted that "the value of a GET can be derived from both its revenue impacts and from learning opportunities of deploying a GET"[46] and recommended that the Commission consider the nascency of GETs in Minnesota when establishing threshold values for GETs to be included in implementation plans.

DOC noted that FERC requires that long range transmission plans use a *minimum* BCR of no more than 1.25.[47] Ensuring that projects have a BCR at 1.25 or above helps to mitigate risks from uncertainty in price or benefit accrual, increasing confidence that a project will be cost beneficial.

The Department asserted that the nascency of GETs in Minnesota warrants the use of a lower BCR in some cases to ensure that more projects move forward. The Department would like to see at least five projects demonstrating each type of GETs in the state.

The Department described the GETs projects in Minnesota that it is aware of to-date. All three use DLR technology, but from three different vendors:

- Xcel Energy's 2023 DLR LineVision project in Monticello
- GRE's 2024 DLR Heimdall project
- GRE's 2025 DLR Prisma Photonics project

The Department asserted that "DLR and DTR have localized benefits and pose minimum risks to the transmission system, which warrant a lower BCR to incentivize more of these projects. For the first five DLR and DTR projects, it is appropriate to employ a BCR of 0.75, if five projects cannot be generated at a BCR of 1.0."[48]

In contrast, PFC and TO can cause congestion to move to new areas of the grid, and therefore the Department asserted it would be more appropriate to employ a higher (more conservative) BCR of 1.25, which will increase confidence that the project is cost effective. Staff summarize the Department's recommended threshold values in Table 4 below.

Table 4: Department Recommended Threshold Values

GETs Type	**Primary BCR Threshold Value**	**Secondary BCR Value** *(used if five projects do not pass the primary threshold)*
Dynamic Line Rating (DLR)	1.0	0.75
Dynamic Transformer Rating (DTR)	1.0	0.75
Power Flow Controller (PFC)	1.25	none
Topology Optimization (TO)	1.25	none

In contrast, MTO opposed setting specific BCR values on the front end to determine whether to

[46] Department Comments at 5

[47] Department Comments at 5, citing to: FERC Order 1920. See page 25. Day Pitney, LLP. FERC Final Rule on Transmission Planning – Order No. 1920. (May 16, 2024). Available at: https://www.iso-ne.com/staticassets/documents/100011/a05_nepool_counsel_memo_transmission_planning_final_rule.pdf

[48] Department Comments at 6

pursue a specific GETs project. MTO argued that its recommended approach, to calculate specific payback periods based on specific types of GETs, is reasonable, practical, and appropriate.[49]

4. Staff Analysis

Party recommendations varied widely on whether and how to set a threshold value for GETs projects to be included in the implementation plan.

MTO recommend not establishing specific values, which would provide maximum flexibility for transmission owners in determining which projects to include in their GETs implementation plans. This has the benefit of enabling MTO to consider hard-to-quantify factors such as ability to advance state policy goals, equity, environmental justice, and workforce goals when selecting projects to propose for development. On the other hand, this approach is less transparent and understandable for stakeholders, the Commission, and GETs vendors, and would require the Commission to make case-by-case assessments of GETs projects during review of the 2025 GETs Report. If the Commission favors MTO's approach, it can adopt it with **Decision Option 5**. Staff recommends adopting **Decision Option 5A** alongside it, which asks MTO to explain its reasoning for the thresholds used to determine which projects are included in the implementation plan.

WATT's recommendation to use a five-year payback period threshold would be simple to administer and is the option most consistent with the plain language of the 2024 GETs Law. While WATT's recommended methodology for valuing congestion is more complex due to using APC modeling, the five-year payback period would apply a clear, consistent test to all potential GETs. Five-year planning horizons are also commonly used in other areas of utility planning including integrated resource plans (which focus on the five-year action plan) and integrated distribution planning which employs a five-year budget forecast.

Staff notes that one possible drawback of WATT's proposed methodology and five-year test is that it could reduce the number of GETs projects that meet the threshold for inclusion in the implementation plan. As discussed in the previous section, parties generally agree that APC modeling can underestimate congestion. WATT characterized the five-year payback window as a high bar for GETs deployment. In combination, these two features could reduce the pool of projects. However, given that some GETs examples discussed in the record had payback periods between six months and three years, it is possible that many projects would pass the five-year test regardless. Staff concludes that WATT's proposed threshold value of five years is reasonable **(Decision Option 6)**.

The Department also offered a clear, consistent framework of threshold values for evaluating proposed GETs, and Staff appreciates the logic of applying a higher threshold to projects that may entail more ratepayer risk. By lowering the threshold value if necessary, in order to achieve five projects of each type, the Department's approach seeks to ensure that MTO proposes a robust GET implementation plan that enables utilities to gain experience with several

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[49] MTO Reply Comments at 2

technologies. This approach prioritizes having at least ten GETs projects over pure cost effectiveness.

Staff has two primary concerns with the Department's approach. First, the Department's threshold values require use of a BCR methodology, while the 2024 GETs law directs that the implementation plan shall include projects "at which the payback period is less than or equal to a value determined by the commission"[50] (emphasis added). While BCR is a method frequently used for assessing cost effectiveness of utility investments, the 2024 GETs Law directs that the Commission set a threshold value using payback period.

Second, Staff believes the Department's recommended thresholds may in general be significantly easier for GETs to meet than the five-year test proposed by WATT. This is because a BCR of 1 indicates that a project is anticipated to have benefits equal to its cost over the duration evaluated (for a capital investment, usually over the asset's useful life). Based on comments in this record, some GETs can be expected to produce savings in excess of their cost in periods as short as 0.5-3 years. Staff anticipates most GETs will have useful lives longer than three years, given typical asset lives seen in other utility hardware and software investments, and therefore many projects may meet the Department's proposed BCR thresholds. This is not necessarily a problem, as MTO and the Commission can use other factors to prioritize among cost effective projects, if prioritization is needed. Such other factors are discussed in Part II.

Additionally, if approving the Department's threshold values, Staff recommends directing MTO to work with the Department in advance of filing the 2025 GETs Report to clarify key elements. BCRs are often calculated from various perspectives, to show the relative cost-effectiveness to different entities. In Minnesota, cost effectiveness tests are often performed comparing the BCR from the perspective of the utility, a program participant, ratepayers, and society.[51] The Department did not specify whether it recommends transmission owners use a specific type of BCR or employ multiple tests to evaluate GETs projects from a variety of perspectives.

Therefore, if the Commission approves the Department's threshold values **(Decision Option 7, subparts A and B),** Staff recommend that it also adopt **Decision Option 8** to direct MTO consult with the Department and explain its BCR methodology in the 2025 GETs Report:

8. Transmission owners shall consult with the Department of Commerce on the BCR methodology that will be used to assess GETs project for inclusion in the implementation plan. In 2025 GETs Reports, transmission owners shall explain which BCR perspective(s) were analyzed (e.g., utility, ratepayers, society, other), explain each cost and benefit factor included in the BCR, and provide workpapers showing calculations and how each input was quantified. (Staff Option)

Similarly, the Department did not provide a recommended BCR value for GETs that may fall

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[50] Minnesota Session Laws, 2024, Chapter 127, Article 42, Section 52

[51] See: Decision, In the Matter of 2024-2026 Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities, March 31, 2023, Docket No. E,G999/CIP-23-46; Xcel Energy Petition for Load Flexibility Pilot Programs and Financial Incentive Mechanism, February 1, 2021, Docket No. E002/M-21-101, at 44-45.

outside of the four categories it identified, or that contain multiple types of GETs. Therefore, if the Commission approves the Department's threshold values **(Decision Option 7, including subparts A and B),** Staff recommend that it also direct MTO to recommend threshold values for other types of GETs, or projects with multiple types, *if* any such projects are included in the cost-effectiveness evaluation **(Decision Option 7, subpart C)**.

7.C. For any projects falling outside of the categories identified above, or that contain multiple GET types, transmission owners shall propose a threshold value to use in assessing whether the project should be included in the implementation plan and explain their reasoning. (Staff Option)

D. SCOPE OF THE GETS COST EFFECTIVENESS ANALYSIS

As described above, the 2024 GETs Law requires affected transmission owners to identify in their 2025 GETs Reports two sets of locations with high levels of congestion: Subd. 2 clause (1) requires reporting locations that had high congestion during the past three years, while Subd. 2 clause (3) requires reporting locations likely to experience high congestion in the next five years.

The 2024 GETs Law requires affected transmission owners to evaluate the cost-effectiveness of GETs solutions in areas with recent congestion (clause 1) and does not specify an analysis regarding areas expected to have congestion in the future (clause 3). However, some parties recommended that the Commission require transmission owners to include areas of future congestion in their analysis, and the Commission can choose whether expanding the analysis in this way is consistent with the public interest.

1. Evaluating Areas with Recent Congestion

MTO recommended against asking transmission owners to quantify the estimated costs of future congestion or to evaluate the cost effectiveness of GETs for locations anticipated to experience future congestion, largely due to the uncertainty involved in identifying the locations of future congestion. MTO expressed concern that modeling tools cannot accurately predict which areas will experience congestion.

Additionally, MTO noted that when FERC Order 881 is implemented, AAR will be required for transmission lines under MISO's control. AAR is expected to reduce congestion and may do so at a lower cost than other GETs. Therefore, MTO expressed concern that the incremental benefits of GETs will decline after Order 881 is implemented in the coming years.

2. Evaluating Areas with Both Recent and Expected Congestion

Other parties, including the Department, EDFR and WATT recommended that the Commission direct transmission owners to evaluate the cost-effectiveness of GETs solutions for both past and future sets of locations.

The Department recommended that GETs projects should be studied for all current and projected areas of congestion, so long as the project can generate benefits for a minimum of two operational years. The Department wants to avoid deploying GETs at locations where forthcoming system changes or infrastructure upgrades mean a GETs will not have sufficient time to accrue benefits that offset its cost. However, the Department noted that if the GET may continue to provide benefits even after a traditional upgrade (perhaps at a lower rate), the GETs should still be evaluated.

WATT and EDFR both recommended transmission owners look at both historical and forecasted congestion, including by studying the impacts of future planned outages on power flows. Due to the potential for short lead times and quick payback periods with GETs deployment, both EDFR and WATT noted that GETs can be cost-effective to mitigate the impacts of even temporary planned outages, (such as those for LRTP construction, hypothetically), or other short-term binding constraints.[52,53]

WATT emphasized that future congestion is foreseeable and already modeled in transmission planning.[54] WATT pointed to a 2023 MISO study showing that modeling of future congestion tends to only identify a small fraction of actual congestion,[55] but asserted that congestion due to planned transmission outages has a higher degree of certainty. MISO's 2024 Near-Term Congestion Study Report is an example of studying congestion impacts of outages associated with transmission expansion plans.[56]

Regarding historical congestion, WATT recommended that transmission owners explain whether historical congestion is expected to be recurring or not. For example, some congestion could be due to an outage that is not likely to occur again due to changes on the system. WATT did not specify whether it recommends that locations where congestion is unlikely to recur be excluded from the analysis, or whether this is primarily a reporting recommendation to provide greater transparency.

WATT also suggested that GETs can be cost-effective in mitigating impacts of moderate congestion, which may not be scrutinized for mitigations through traditional planning processes where solutions are more expensive.

3. *Evaluating Combinations of GETs and Traditional Upgrades*

The Department recommended that transmission owners' analysis of GETs study various combinations of both GETs and traditional upgrades for areas of current or future congestion, including:

(i) interactions of multiple GETs,

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

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52 EDFR Comments at 5

53 WATT Initial Comments at 4

54 WATT Reply Comments at 1

55 MISO Economic Planning Team, Update on MTEP23 Near Term Congestion Study, MISO Planning Subcommittee, August 9, 2023 https://cdn.misoenergy.org/20230809%20PSC%20Item%2007%20Near-Term%20Congestion%20Studies629799.pdf

56 MISO, 2024 Near-Term Congestion Study Report, October 2024, https://cdn.misoenergy.org/MTEP24%20Near-Term%20Congestion%20Study%20Report657728.pdf

(iii) substation or transformer upgrades in isolation.[57]

The Department made this recommendation in part because it is concerned "that GETs solutions studied in isolation may not produce a sufficient number of viable projects."[58] For example, in Docket No. E999/CI-24-316, regarding solutions to curtailment in southwest Minnesota, Xcel stated that DLR may not provide a sufficient increase in capacity to alleviate the congestion in this area and is not a substitute for expanding transmission infrastructure. (However, Xcel agreed that TO can help to alleviate congestion in the region and is doing further evaluation of PFC technology to determine its applicability).[59]

The Department emphasized that due to the nascency of GETs in Minnesota, it would be beneficial for MTO to gain operational experience with a range of GETs technologies. The Department would like to see at least five GETs pilots for each technology type.[60] Studying GETs in combination may help to achieve this goal.

MTO acknowledged this recommendation and stated that it would evaluate whether the GETs analysis can be expanded to evaluate combinations of GETs and traditional upgrades. However, MTO noted the GETs analysis is already underway and due to the filing date of November 1, 2025, it may have somewhat limited ability to expand the analysis.[61]

4. *Staff Analysis*

a. Evaluating Locations of Recent vs. Future Congestion

Parties disagreed about the usefulness of evaluating GETs for locations expected to have future congestion. MTO expressed concern that modeling of future congestion is too uncertain, but the record on this topic is limited. Utilities and the Commission must rely on forecasts in many areas of utility operations and investment planning. Without more record development on the level and types of uncertainty in congestion modeling it is challenging to evaluate this concern.

More information about the accuracy of models in forecasting *locations* of congestion and the *scale* of congestion would aid the Commission's decision making on this issue. Staff provides **Decision Option 11** to ask for more record development in the 2025 GETs Report:

11. In the 2025 GETs Report, transmission owners shall provide information on the capabilities and limitations of modeling and forecasting congestion, including APC modeling. Transmission owners shall discuss:
    A. An overview of the most common approaches used to evaluate current and future congestion, and the use cases or applications of each.

57 Department, Initial Comments at 10-11

58 Department, Initial Comments at 10

59 Xcel Reply Comments, November 12, 2024, Docket No. E999//CI-24-316, at 6; Xcel Supplemental Comments, December 3, 2024, Docket No. E999/CI-24-316, Attachment A

60 Department, Initial Comments at 5

61 MTO Reply Comments at 4

B. An explanation of each step in APC modeling and a description of the modeling tools used.

C. The level of accuracy of APC and other relevant modeling approaches in forecasting future locations of congestion, the frequency of future congestion, and the cost of future congestion.

D. Best practices for minimizing uncertainty or the risks associated with uncertainty, including through benchmarking modeling results using historical data.

E. An example APC calculation for at least two different locations with high congestion, illustrating how APC would be used to quantify the cost of future congestion and savings attributable to a potential GET deployment.

(Staff Option)

However, as parties pointed out, transmission system outages due to construction of approved projects are more certain. The 2024 GETs law requires MTO to identify areas "likely to experience high levels of congestion during the next five years." Therefore, it would be consistent with the statute for MTO to consider the *likelihood* that congestion will occur in addition to estimating the future cost of congestion, when identifying these locations.

Therefore, Staff believes it would be reasonable to ask MTO to model power flows associated with known or reasonably foreseeable transmission outages, to identify areas of high congestion associated with these outages, and to include these locations in the GETs Report's technical feasibility and cost effectiveness evaluations **(Decision Option 10).**

Staff also finds reasonable WATT's recommendation that transmission owners explain whether recent congestion in identified areas is expected to continue or not **(Decision Option 17)**.

The Department's recommendation **(Decision Option 9)** to evaluate GETs for all areas of current or forecasted congestion would provide a comprehensive view of GETs applicability but may significantly expand the analysis. While the Department recommended that a GETs cost effectiveness evaluation only be included in the 2025 GETs Report if the project will have at least two years of operational benefits, Staff's understanding is that this would still require transmission owners to evaluate GET options at *all* locations of current and forecasted congestion, in order to ascertain operational windows.

Given that the 2025 GETs Report will be the first time that transmission owners, stakeholders and the Commission are evaluating the cost effectiveness of a range of GETs solutions statewide, Staff anticipates that there will be a learning curve and sees benefits to prioritizing areas for analysis.

For a similar reason, while Staff appreciate WATT pointing out that GETs may be uniquely positioned to mitigate impacts of *moderate* congestion that are challenging to address through traditional means, Staff asserts that it would be reasonable to revisit this issue in a future GETs analysis. If the Commission prefers, it could direct MTO to discuss the applicability of GETs for areas of moderate congestion in its 2025 GETs Report or revisit the issue with the 2027 BTPR.

b. Evaluating Combinations of GETs and Traditional Upgrades

MTO stated it would attempt to evaluate combinations of GETs and traditional upgrades as the Department recommended, though it could not state to what extent this would be feasible given the filing date of November 1. The Department's recommendation **(Decision Option 12)** would add complexity and time to the analysis, but Staff agrees it may yield informative results and potentially help optimize both GETs and traditional upgrades. Given the 2025 GETs Report is the first such analysis, and that the analysis is already underway, Staff finds it reasonable for MTO to work to incorporate the Department's recommendation to the extent possible, and to report on its efforts and learnings from evaluating combinations of GETs and traditional upgrades in the November 1 filing. Staff offers the following **Decision Option 13** to direct such reporting from MTO:

13. In the 2025 GETs Report, transmission owners shall report on efforts to evaluate and compare:
    (i) combinations of GETs,
    (ii) combinations of GETs with traditional upgrades, and
    (iii) traditional upgrades such as transformer or substation upgrades.
    Transmission owners shall describe learnings from this effort that may inform future GETs evaluations. (Staff Alternative)

II. OTHER ISSUES

A. Equity, Environmental Justice and Workforce Considerations

Commenters generally agreed that the Commission can and should consider additional factors when evaluating the 2025 GETs Report, and agreed that GETs may have equity, environmental justice, and workforce or other local benefits. MTO and the Department both supported consideration of equity, environmental justice and workforce factors during the GETs evaluation, and suggested that Minnesota statutes can provide a framework for doing so.

For example, the Department recommended[62] that the Commission consider the same factors in evaluating GETs as it is required to consider under Minn. Stat. § 216B.1691, subd. 9(a) (directing the Commission to maximize local benefits of the state's renewable energy objectives)[63] and Minn. Stat. § 216B.2422, subd. 4a (requiring consideration of local job impacts in resource plans).[64] MTO recommended that when considering environmental justice impacts, the Commission rely upon the definition of "environmental justice area" recently enacted in Minn. Stat. § 216B.1691, subd. 1(e) and clarified in Commission Order.[65] MTO also suggested that the GETs evaluation process could consider impacts on local communities experiencing tax revenue adjustments due to congestion or other factors which GETs may

[62] Department Comments at 7-8

[63] Minn Stat. § 216B.1691, subd. 9(a)

[64] Minn Stat § 216B.2422, subd. 4a

[65] MTO Initial Comments at 8

partially alleviate, which would help to prioritize projects with local community benefits.

WATT noted that by reducing congestion, GETs enable delivery of lower-cost renewable energy and may particularly reduce the use of peaking plants, which may have local environmental justice and air quality impacts as well as carbon emissions and higher costs.[66] WATT also pointed to research from the Brattle Group that found "deploying GETs nationwide would lead to at least 330,000 short-term construction jobs and 20,000 long-term jobs in energy generation,"[67] made possible due to expanded grid capacity.

1. Staff Analysis

Parties did not provide specific recommendations on how, or during what phase of the evaluation the Commission should consider these factors. MTO suggested more work is likely needed to identify how and when to consider these factors during the GETs evaluation process, and will seek to work with the Commission, the Department and other stakeholders to do so.

Staff offers the following **Decision Option 19** to require transmission owners to consult with stakeholders on how to incorporate equity, environmental justice, and workforce impacts in advance of filing the 2025 GETs Report, and to discuss in the Report whether and how these factors were considered.

19. In the 2025 GETs Report, transmission owners shall explain whether equity, environmental justice, and workforce impacts were incorporated into the GETs evaluation, and if so, describe how and where in the process these factors were evaluated.

    A. In advance of filing the 2025 GETs Report, transmission owners shall consult with the Department of Commerce and other stakeholders on how the GETs evaluation can incorporate equity, environmental justice, and workforce impacts.

    (Staff Option)

B. *Transparency and Information Sharing*

EDFR and WATT both emphasized the importance of transparency and information sharing for independent power producers and other market participants, which they see as key to enabling meaningful stakeholder engagement, robust oversight, and successful deployment. WATT recommended the Commission require transmission owners to share the underlying congestion and GETs modeling assumptions used in public filings to the extent possible **(Decision Option 20).**

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[66] WATT Initial Comments at 6

[67] WATT Initial Comments at 6, citing to the Brattle Group, Unlocking the Queue with Grid Enhancing Technologies, February 2021, at 11.

1. Staff Analysis

Staff agrees that sharing relevant information is important to enable parties and regulators to adequately review the GETs analysis and implementation plan, and ensure it advances the public interest. Minnesota's Data Practices Act governs all filings made with the Commission and requires that information filed with the Commission is public unless appropriately designated as nonpublic.[68] Therefore, while WATT's recommendation is not necessary to ensure that information is shared to the extent possible, Staff does not have concerns with adopting it.

C. GETs Applicability for Moderate Congestion

WATT noted that transmission lines "with moderate, but meaningful, congestion are often not considered for traditional economic or reliability upgrades. For these lines, GETs may be the only cost-effective solution to unlock additional transfer capacity. Deploying GETs on these lines would save ratepayers millions every month by enabling more efficient economic dispatch."[69]

1. Staff Analysis

Such locations are not specifically contemplated by the 2024 GETs Law, which specifies that transmission owners should identify locations with the highest levels of recent or forecasted congestion. As transmission owners, stakeholders, and the Commission gain experience evaluating GETs, it may be beneficial to considering expand the analysis to include areas of moderate congestion. However, in Staff's view, this issue requires more record development and may be more appropriate to address in a future proceeding, such as the 2027 BTPR.

D. Impact of Related FERC Actions

MTO suggested that implementation AAR, as required under FERC Order No. 881, may reduce the need for or incremental benefits of GETs by offering lower-cost solutions. Additionally, MTO raised a concern that if the pending ANPOR in Docket No. RM24-6-000 is finalized, Minnesota utilities may have to comply with two separate sets of rules on DLR. MTO recommends that the Commission consider how to reconcile these requirements.[70]

WATT agreed that AAR can help improve utilization of transmission capacity but argued that AAR should be seen as a minimum compliance tool, not a substitute for GETs. WATT referenced an MIT study which "found that AAR captured only half the benefit of DLR: while AAR enabled 160 MW of additional solar and 800 MW of wind in their study over the ERCOT system, DLR enabled 360 MW of solar and 2,250 MW of wind generation. Further, DLR delivered twice the system cost savings as AAR."[71]

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[68] Minn. Stat. §13.03

[69] WATT Initial Comments at 7

[70] MTO Initial Comments at 9

[71] WATT Reply Comments at 7, citing to: Lee, Nair, and Sun, Impact of Dynamic Line Ratings on the ERCOT Transmission System (July 2022), https://www.linevisioninc.com/news/this-mit-study-simulated-dynamic-line-ratings-across-the-ercot-grid-the-results-were-impressive

Regarding the impact of possible future FERC rules on DLR, WATT asserted that Minnesota's GETs law is distinct and complementary, rather than contradictory. While FERC Order 881, and its potential successor rule (RM24-6-000), are minimum operational requirements, the state law requires transmission owners to evaluate GETs opportunities for cost-effectiveness. WATT also pointed out that the potential FERC rule on DLR is in the ANOPR stage, which means that any final rule is several years away, and the state process is a meaningful opportunity for gaining nearer-term experience while reducing system costs.

DECISION OPTIONS

<u>GETs Payback Period Methodology</u>

The Commission should select Decision Option 1, and Staff recommends also selecting Decision Option 2.

1. Transmission owners shall calculate the cost effectiveness for each potential GETs deployment studied for the 2025 GETs Report using a payback period calculation comparing project costs to average annual savings. (MTO, WATT)

AND

2. Transmission owners shall provide an explanation of each cost and benefit factor included in GETs payback period calculations and provide workpapers showing calculations and how each input was quantified. (Staff Option)

<u>Calculating Congestion Cost</u>

The Commission may choose Decision Option 3A, 3B, 4, or none.

3. Transmission owners shall calculate the cost of historical congestion using:
    A. The shadow price ($/MW) of the constraint
    OR
    B. The congestion charge ($) of the constraint (MTO, WATT)

AND/OR

4. Transmission owners shall calculate the cost of forecasted future congestion and the savings attributable to a potential GET deployment using PROMOD-based Adjusted Production Cost modeling. (WATT)

<u>Payback Period Threshold Value</u>

The Commission should choose between Decision Options 5, 6, or 7 (with subparts A and B). If the Commission selects Decision Option 5, Staff recommends also selecting 5A. If the Commission selects Decision Options 7A-B, Staff recommends also selecting subpart C and Decision Option 8.

5. Transmission owners shall include in the 2025 GETs Implementation Plan a schedule and cost estimate to install GETs 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. (Staff Interpretation of MTO)

    A. Transmission owners shall include in the Report an explanation of and rationale for each threshold value used to determine which projects are included in its proposed GET implementation plan. (Staff Option)

OR

6. Transmission owners shall include in the 2025 GETs Implementation Plan a schedule and cost estimate to install GETs at each congestion point identified at which the payback period is less than or equal to five years, or less than or equal to the expected duration of the congestion if known to be longer than five years. (WATT)

OR

7. Transmission owners shall include in the GETs Implementation Plan a schedule and cost estimate to install GETs at each congestion point identified at which the benefit cost ratio (BCR) meets or exceeds the thresholds below. (Department)

    A. For dynamic line rating (DLR) and dynamic transformer rating (DTR) projects: a benefit cost ratio of at least 1.0, unless five projects of each technology do not meet this threshold. In that case, transmission owners shall use a benefit cost ratio of at least 0.75 to identify additional eligible projects, up to a total of five projects for each technology. (Department)

    B. For power flow controller and topology optimization projects: a benefit cost ratio of at least 1.25. (Department)

    C. For any projects falling outside of the categories identified above, or that contain multiple GET types, transmission owners shall propose a threshold value to use in assessing whether the project should be included in the implementation plan and explain their reasoning. (Staff Option)

AND

8. Transmission owners shall consult with the Department of Commerce on the BCR methodology that will be used to assess GETs project for inclusion in the implementation plan. In 2025 GETs Reports, transmission owners shall explain which BCR perspective(s) were analyzed (e.g., utility, ratepayers, society, other), explain each cost and benefit factor included in the BCR, and provide workpapers showing calculations and how each input was quantified. (Staff Option)

Forecasted Congestion

If the Commission selected Decision Option 4 above, it should select either Decision Option 9 or 10. If the Commission agrees with MTO that it is not necessary or appropriate to evaluate GETs for areas of future congestion at this time, it may skip this section or select Decision Option 11.

9. In preparing the 2025 GETs Report, transmission owners shall evaluate GETs projects for all current and projected areas of congestion, and shall provide this analysis as part of the Report, so long as the project can generate benefits for a minimum of two operational years. (Department)

OR

10. In preparing the 2025 GETs Report, transmission owners shall model power flows associated with known or reasonably foreseeable transmission outages and shall identify any areas of high congestion associated with these outages in the Report. Transmission owners shall include these locations in their evaluations of the technical feasibility and cost effectiveness of GETs in addressing congestion. (Staff Interpretation of WATT, EDFR)

11. In the 2025 GETs Report, transmission owners shall provide information on the capabilities and limitations of modeling and forecasting congestion, including APC modeling. Transmission owners shall discuss:

    A. An overview of the most common approaches used to evaluate current and future congestion, and the use cases or applications of each.

    B. An explanation of each step in APC modeling and a description of the modeling tools used.

    C. The level of accuracy of APC and other relevant modeling approaches in forecasting future <u>locations</u> of congestion, the <u>frequency</u> of future congestion, and the <u>cost</u> of future congestion.

    D. Best practices for minimizing uncertainty or the risks associated with uncertainty, including through benchmarking modeling results using historical data.

    E. An example APC calculation for at least <u>two</u> different locations with high congestion, illustrating how APC would be used to quantify the cost of future congestion and savings attributable to a potential GET deployment.

    (Staff Option)

<u>Combinations of GETs and Traditional Upgrades</u>

The Commission may select Decision Option 12 or 13, and may select Decision Option 14 with either.

12. In the 2025 GETs Report, transmission owners shall evaluate and compare:
    (i) combinations of GETs,
    (ii) combinations of GETs with traditional upgrades, and
    (iii) traditional upgrades such as transformer or substation upgrades. (Department)

OR

13. In the 2025 GETs Report, transmission owners shall report on efforts to evaluate and compare:
    (i) combinations of GETs,
    (ii) combinations of GETs with traditional upgrades, and
    (iii) traditional upgrades such as transformer or substation upgrades.
    Transmission owners shall describe learnings from this effort that may inform future GETs evaluations. (Staff Alternative)

AND/OR

14. If a transmission owner identifies that a potential GET deployment studied for the 2025 GETs Report will shift congestion to another limiting element, it shall calculate and report the cost of addressing that next constraint and assess whether the GET project is cost effective with, or without, the second mitigation. (WATT)

<u>Cost and Benefits to be Considered</u>

The Commission may select Decision Option 15 (in full or in part) or Decision Option 16, or neither.

15. Transmission owners shall consider, and quantify to the maximum reasonable extent, the following costs and benefits when calculating the cost effectiveness of each potential GET deployment studied for the 2025 GETs Report:

    <u>*Costs:*</u>

    A. The capital and O&M costs of the GETs project (MTO, DOC, WATT)
    B. The capital and O&M costs of any physical or cyber security investments necessary for implementation of the GET(s) (MTO)
    C. The following costs, if not otherwise included in capital or O&M:
        i. Cost of design work and installation (MTO, WATT)
        ii. Cost of licensing (MTO, WATT)
        iii. Cost of outages during construction (MTO, WATT)
        iv. Incremental wear and tear from reconfiguration, if applicable (WATT)

    <u>*Benefits:*</u>

    D. Avoided costs of energy (MTO, WATT)
    E. Avoided costs of outages (MTO, EDFR)
    F. Ability to serve more load (MTO)
    G. Ability to perform maintenance in opportune windows (MTO)
    H. Reduced renewable curtailment (DOC, EDFR, WATT)
    I. Reduced transmission congestion (DOC, EDFR, WATT)
    J. Reduced price differentials (DOC)
    K. New asset deferral (DOC)
    L. Improved situational awareness (DOC, EDFR, WATT)
    M. Resilience and contingency support (DOC, EDFR, WATT)
    N. Asset health monitoring (DOC, EDFR, WATT)
    O. Reduced cost of new interconnection (DOC, EDFR, WATT)
    P. Improved transfer capability across regions (EDFR, WATT)
    Q. Ability to advance state policy aims (EDFR)

OR

16. When identifying which costs and benefits to include in the GETs cost effectiveness evaluation, transmission owners shall consider the comments submitted in Docket No. E999/M-25-99. Transmission owners shall quantify, to the maximum reasonable extent, all relevant costs and benefits for each GET deployment, and explain their reasoning for

inclusion or exclusion of factors in the 2025 GETs Report. (Staff Alternative)

Reporting Requirements

The Commission may select any combination of Decision Options 17-20.

17. For each location identified in the 2025 GETs Report as experiencing a high level of congestion during the past three years, transmission owners shall explain whether congestion is expected to be recurring, and why or why not. (WATT)

18. In developing the 2025 GETs Report, transmission owners shall consult with GET vendors and other stakeholders during the modeling process to ensure that modeling best practices are considered and applied as appropriate, and that modeling results reflect probable and realistic outcomes. Transmission owners shall verify in 2025 GETs Reports that this consultation took place. (Staff Interpretation of WATT)

19. In the 2025 GETs Report, transmission owners shall explain whether equity, environmental justice, and workforce impacts were incorporated into the GETs evaluation, and if so, describe how and where in the process these factors were evaluated.

    A. In advance of filing the 2025 GETs Report, transmission owners shall consult with the Department of Commerce and other stakeholders on how the GETs evaluation can incorporate equity, environmental justice, and workforce impacts.

    (Staff Option)

20. Transmission owners shall share the underlying congestion and GETs modeling assumptions used in their 2025 GETs Report and associated filings to the extent possible. (WATT)