Appendix B

Minnesota 2025
Grid Enhancing Technologies (GETs)
Study Report

October 31, 2025

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Introduction

As enacted by the 2024 Minnesota Legislature,[1] Minnesota transmission owning utilities are required to submit a report on Grid Enhancing Technologies (GETs or GETS Report) in conjunction with the 2025 Biennial Transmission Plan Report (2025 BTPR).

The legislation states that any electric utility owning more than 750 miles of transmission in Minnesota must review historical congestion facilities, determine GETs solutions for each congestion point, and develop implementation plans for those GETs solutions that meet Commission defined payback period.[2] GETs are 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.

The GETs Report addresses 30 solutions that are being developed to address congestion in the near term. This report details historic and future congestion information for the Grid North Partners' (GNP),[3] ITCM, and MPC footprint within Minnesota as needed for the "Grid Enhancing Technologies Report" and meets the requirements of the legislation and the Minnesota Public Utilities Commission's (Commission or MPUC) September 10, 2025 Order Establishing Requirements (GETs Order).[4] [5]

The legislation also requires identification of potential congestion issues over the next five years as well as a description of a utility's line rating methodology. Given that the Minnesota transmission system is highly interconnected and there are many instances where a transmission facility has multiple owners, the Minnesota utilities decided to develop the report as a joint effort. In 2023, the GNP utilities worked together on a study to identify 19 near-term solutions to pervasive congestion problems in Minnesota. When GNP announced the near-term projects, plans were also announced to conduct a second iteration of the study after Midcontinent Independent System Operator's (MISO) LRTP Tranche 2.1 portfolio was solidified. Due to the similar

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[1] 2024 Minn. Laws, Ch. 127, Article 42, Section 52.

[2] In response to Order Point 4(f), the MTO's analysis included a qualitative review of equity, environmental justice and workforce impacts into the overall analysis by incorporating the impacts that cost-effective GETs will have in enhancing Minnesota's transmission and generation resources.

[3] Grid North Partners, an evolution of CapX2020, is a voluntary partnership of ten Minnesota and surrounding area transmission-owning utilities. The Grid North Partners members include Central Municipal Power Agency/Services, Dairyland Power Cooperative, Great River Energy, Minnesota Power, Missouri River Energy Services, Otter Tail Power Company, Rochester Public Utilities, Southern Minnesota Municipal Power Agency, WPPI Energy, and Xcel Energy.

[4] See Commission's September 10, 2025 ORDER ESTABLISHING REQUIREMENTS, in Docket No. E999/M-25-99.

[5] The MTO is coordinating with the Minnesota Department of Commerce on the consultation requirements under Order Point 4(f) in conjunction with the Department retaining its expert consultant. The stakeholder consultation requirement will be completed after this report is filed.

mandated outcomes of 2024 legislation on GETs, the second iteration of the GNP study was merged into this study.

This study is one of several efforts to address congestion throughout Minnesota. Regional planning efforts, including the MISO Long Range Transmission Plan (LRTP), also work to, among many other system needs, address congestion throughout the transmission system.[6]

The GETs Report utilizes historic congestion data for the past three years[7] (2022 – 2024) from MISO Day-Ahead reports.[8] This report only includes constraints located in Minnesota from the following transmission owners: **Great River Energy (GRE)**, **Minnesota Power (MP)**, **Xcel Energy (NSP/Xcel)**, **Otter Tail Power Company (OTP)**, **ITC Midwest (ITCM)**, Missouri River Energy Services, Southern Minnesota Municipal Power Agency (SMP), and Minnkota Power Cooperative (MPC). The bolded entities (GRE, MP, Xcel, OTP, and ITCM) each own more than 750 miles of transmission and are subject to the legislation requirements. MRES, SMP, and MPC also participated in the study effort but were focused on facilities jointly owned with utilities subject to the GETs legislation requirements.

The Minnesota transmission system is highly interconnected and many of the facilities identified in this report may have multiple owners. In total there were 66 constraints in Minnesota included in this report that showed 168 or more hours of congestion in at least one of the prior three years.

The 66 high congestion constraints are separated into seven categories:

Constraint Category	Description	Number of Constraints
Constraints with Solution Proposals (Payback Period Threshold Met)	This section covers the constraints where a new solution (either GETs, traditional, or a combination of both) was identified and the MPUC defined payback threshold of five years was met. Given that congestion tends to easily shift to adjacent or nearby facilities, solutions may extend beyond just the driving constraint. Implementation plans for each solution are included.	12
Constraints with Solution Proposals (Payback Period Not Yet Determined)	This section covers the constraints where a new solution (either GETs, traditional, or a combination of both) was identified and additional analysis is needed to determine if the MPUC defined payback threshold of five years was met. Given that congestion tends to easily shift to adjacent or nearby facilities, solutions	7

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[6] See Commission's September 10, 2025 ORDER ESTABLISHING REQUIREMENTS, in Docket No. E999/M-25-99, Order Point 4(g).

[7] See Commission's September 10, 2025 ORDER ESTABLISHING REQUIREMENTS, in Docket No. E999/M-25-99, Order Point 4(a).

[8] MISO Market Reports

	may extend beyond just the driving constraint. Implementation plans will be developed for those solutions meeting the MPUC defined payback threshold.	
Constraints without Solution Proposals that Meet the Payback Period Threshold	This section covers the constraints where a new solution (either GETs, traditional, or a combination of both) was NOT identified	2
Constraints with Solution Proposals (Payback Period Threshold NOT Met)	This section covers the constraints where a new solution (either GETs, traditional, or a combination of both) was identified and the MPUC defined payback threshold of five years was NOT met. Implementation plans for solutions are NOT included.	2
Constraints with Completed or Pending Projects	Some constraints had projects completed within the past three years or have planned projects in the next few years that were developed prior to this required study and are already part of past, present or future MISO MTEP cycles. These constraints are identified here for completeness. No further solution considerations were made for these, but the implemented or planned solutions are described instead.	18
Constraints Driven by Temporary Outages or Operations Conditions	Transmission outages can play a significant role in driving market congestion. Some of these constraints are strongly linked to unique transmission outages and appear only for the duration of these specific outages. This section covers these instances of congestion and solutions generally were not identified. This section only includes constraints that had one span of congestion tied to one specific outage or set of outages. A constraint that was outage driven and showed up over more than one span would have a solution developed and be part of the "Constraints with Solution Proposals" sections. In addition, some constraints are driven by unique operations conditions. Such constraints generally include radial generation ties or radial load serving lines where temporary reconfigurations may have introduced congestion for a limited time. These constraints have impacts isolated to specific load or generation facilities.	17
Constraints with High Congestion Only in Future Models (168+ Hours) (Monitor for future projects)	In addition to the historic constraint categories there is a separate category for future constraints (""). These were determined by running production cost modeling simulations via PROMOD (discussed in the "Details About Future Models" section). This section includes constraints that showed 168 or more hours of congestion	8

	in the future models but were under the 168-hour threshold in the historic data. These constraints will continue to be monitored in future studies. Also included is a short category noting the congestion associated with several interfaces that appeared in the day-ahead market. Interfaces are made up of more than one transmission facility. Solutions specific to these interfaces were not developed; however, some of the individual constraints in the report are elements of these interfaces.	

The data for each constraint is laid out in a standardized template. The details of each part of this template are covered in the "Template Details" section.

General Definitions

This section defines the technical terminology used in this report.

Shadow Price: This value represents the change in production cost by relieving a transmission constraint by one MW. Shadow price is reported hourly for each constraint on the system in the day-ahead reports from MISO. When a transmission facility reaches its flow limit it becomes a binding constraint, and the Security Constrained Economic Dispatch (SCED) must dispatch more expensive generation out of economic merit order to circumvent the constraint. To quantify the impact on market prices (locational marginal prices or LMPs) of the system, the SCED will rerun the dispatch with the constraint's rating increased by one MW and note the change in system production costs. The difference in production costs with and without the one MW increase is the shadow price of the constraint. Given that increasing a constraint's rating by one MW should enable less expensive generation, shadow price values are mostly negative, representing a decrease in system costs. However, in rare instances shadow price values may be positive which denotes that increasing the constraint's rating by one MW increases system costs and thus the original congestion was beneficial. This may be that alleviating the existing constraint shifts congestion on the system to a more problematic area. Constraints with positive shadow prices are usually radial gen ties. Throughout this report, constraint shadow prices are reported as annual totals. This value should not be mistaken for the complete cost savings associated with fixing a constraint as most constraints will need more than just one MW of additional capacity.

Congestion Charge: This is a value designed to capture the total cost of a constraint on the market. Instead of a marginal one MW, the congestion charge takes the shadow price at each hour and multiplies it by the full rating of the constraint for that hour. The rating may vary depending on the season of occurrence (summer vs. winter) and whether the constraint appears under system intact conditions (thus using a "normal" rating) or under post-contingent conditions (thus using an "emergency" rating). This value may also be known as "Congestion Rent."

ARR/FTR: Auction Revenue Rights (ARR) and Financial Transmission Rights (FTRs) are used by market participants to hedge against financial risks associated with congestion cost fluctuations in the day-ahead energy market.

Congestion Charge (ARR/FTR Adjusted): An adjusted congestion charge value that accounts for any profits associated with a TO's financial transmission rights (FTRs) or Auction Revenue Rights (ARRs). The ARR/FTR adjustment process is detailed below.

Ambient Adjusted Ratings (AAR): Technology used to adjust a facility's ratings based primarily on ambient temperature and solar heating forecasts.

Grid Enhancing Technology (GETs): 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.

Dynamic Line Ratings (DLR): Hardware or software used to calculate the thermal limit of existing transmission lines at a specific point in time by incorporating information on real-time and forecasted weather conditions. DLR considers more variables than AAR such as cooling effects due to wind.

Advanced Power Flow Controller: Hardware and software used to reroute electricity from overloaded transmission line to underutilized transmission lines. This is typically accomplished using a variable impedance.

Topology Optimization: Software technology that uses mathematical models to identify reconfigurations in the transmission grid to reroute electricity from overloaded transmission lines to underutilized transmission lines. This is commonly achieved by opening breakers in the system.

Advanced Conductors: Transmission conductor technology that utilizes more sophisticated materials to withstand higher temperatures with reduced thermal sag which allows for a higher facility rating.

Accounting for Financial Transmission Right (FTR) profits in Congestion Charges

FTRs are used in the MISO market to allow a holder to hedge against congestion costs in the day-ahead energy markets. An FTR is defined from a source node to a sink node for a specified MW value. When congestion occurs in the day-ahead market for a given hour, the FTR holder is either paid or must pay a fraction of the overall congestion charge for that hour depending on the direction of the congestion relative to the FTR source and sink. As part of this study, the Commission's GETs Order required that FTR profits be accounted for each constraint's congestion charge to ensure that the full cost of congestion is accounted for.[9]

FTRs are defined from a source node to a sink node, and these nodes may be on each side of the constraints or even the same side of the constraint. Taking the FTR profits, which are determined by the entire market conditions, for a given hour and assigning a portion of the profit to individual constraints is a complicated process and thus an approximation technique was used in this report. To approximate the FTR adjustments, an approach based on a method for "Allocating CRR Revenue Inadequacy by Constraint to CRR Holders" described in a whitepaper by the California ISO Department of Market Monitoring in 2014 was used.[10]

The fundamental equation used to apply a fraction of an FTR's annual profit to an individual binding constraint is as follows:

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

This equation states that the share of profit from FTR *m* applied to constraint n equals the overall annual profit of FTR *m* multiplied by the shift factor difference between the FTR's source and sink relative to constraint n. Shift factors (also known as distribution factors) measure the percentage of flow that would occur on a line after injecting one MW at the associated node. Every branch has a unique shift factor associated with every single node. The difference between source and sink shift factor of an FTR provides a percentage of flow expected on a specific branch resulting from transfers between that FTR's source and sink. Multiplying this percentage by the FTR's total profit results in a portion of the FTR's profit being associated with constraint n. Shift factors are completely dependent on the transmission topology and the amount of load or generation at the location is irrelevant. The absolute value of the shift factor is taken so that the sign of the profit share is dependent entirely on whether the profit was positive or negative.

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[9] See Commission's September 10, 2025 ORDER ESTABLISHING REQUIREMENTS, in Docket No. E999/M-25-99, Order Points 3 and 4.

[10] https://www.caiso.com/Documents/AllocatingCRRRevenueInadequacy-Constraint-CRRHolders_DMMWhitePaper.pdf

A market participant usually has many FTRs active at once for a specified time so a portion of all FTR profits must be applied to each constraint. This results in an overall adjustment to the congestion charge of:

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

Constraint n's FTR Adjusted Congestion Charge is the original congestion charge plus this FTR Adjustment value for all FTRs. Given that FTR's may be both positive and negative, the overall adjustment may either increase or decrease the final congestion charge.

This FTR adjustment would be calculated based on every FTR across all FTR holders in MISO.

A simplified example of this calculation is shown below:

Assume the following three FTRs:

FTR Name	**Source**	**Sink**	**Profit**
FTR_1	A	B	$R_{1,1}$
FTR_2	A	C	$R_{2,1}$
FTR_3	D	C	$R_{3,1}$

And assume the following binding constraint:

Constraint Name	**Congestion Charge**	**FTR Charge**	**Congestion**
Constraint 1	X_1	Z_1	

Then the FTR Congestion Charge calculation is (where SF stands for "shift factor):

$$Z_1 = X_1 + [SF_{AB,1} * R_{1,1} + SF_{AC,1} * R_{2,1} + SF_{DC,1} * R_{3,1}]$$

Where:

> $SF_{AB,1} = |SF_{SRC,A} - SF_{SINK,B}|$ for "Constraint 1" taken from the PROMOD 2025 model (Note that the SF values are unique to Constraint 1. All other constraints would have different SF values.)

Given that most congestion charges in the report are costing the system (i.e. negative), FTRs that are profitable (i.e. positive) will reduce the constraint's congestion charge magnitude (the FTRs successfully hedged against congestion costs and reduced the impact on ratepayers). However, using this method, there are some years for certain constraints where this adjustment may be greater than the overall congestion. Applying the complete adjustment in these instances would flip the congestion charge sign from negative to positive implying that the congestion is then a net positive for the system. Instead, the congestion charge will be set to zero implying that the FTR hedge completely covered the congestion issue for that year.

For example:

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

This is the initial MTO effort in investigating and undertaking a method for adjusting congestion costs by FTR profits. The method used in this report is based on similar methods used in other regions in the United States[11] but does have some identified deficiencies that are highlighted below.

1. FTRs Across the Entire MISO Footprint Impact Congestion
    a. For this report FTRs from GRE, MP, MRES, OTP, and Xcel were accounted for in making congestion charge adjustments. However, other market participants across MISO participate in the FTR market to hedge against congestion which would impact the resulting adjusted congestion charge. It is not possible to get all FTR information from all MISO market participants to apply to all constraints.

2. Shift Factors and Congestion are Topology Dependent
    a. The shift factors for this calculation were taken from a near-term PROMOD simulation with topology closely resembling 2025 conditions with no outages considered. However, hourly congestion and FTR revenues in the MISO market depend on the hour-by-hour conditions of the transmission system. Changing outages or new transmission projects change the system shift factors in each hour. A perfect congestion charge adjustment would use hourly shift factors based on historical system conditions instead of a single set; however, getting this hourly information is not feasible.

3. Shift Factor Information is Based on Individual Buses. FTRs May Be Based on Aggregate Hubs
    a. For an FTR, the source and sink nodes may be pricing nodes that are aggregates of many different system buses over a wide geographic and electrical area (Ex: MINN.HUB). Shift factors themselves are calculated based on only a single bus. Shift factors for these aggregate pricing nodes were calculated as a peak load-weighted average shift factor with peak load values taken from the near-term PROMOD model.

Despite these issues, the MTO is confident that the method used in this report provides the valid way to adjust congestion costs by FTR profits values.

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[11] See California ISO, INITIATIVE: Congestion revenue rights enhancements, available at: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Congestion-revenue-rights-enhancements

Prior Congestion Studies

In 2023, the Grid North Partner (GNP) member utilities conducted a study to identify points of congestion on their systems and identify those that could be solved both the quickest and at the least cost. Through this effort, many of these “low-hanging fruit” constraints have either already been addressed or have pending solutions. In total, 19 transmissions solutions were developed as part of this effort at an estimated cost of $130 million and this is described further in Section 9.3 of the Biennial Report. Many of the remaining congestion concerns may not be as straightforward or inexpensive to solve even when considering GETs projects (especially considering the relative infancy of GETs technology use in Minnesota). In addition, GETs projects like DLR may require non-GETs upgrades such as terminal equipment replacement to realize any benefit. Alternatively, a facility could be presently limited by terminal equipment and thus the best solution is to simply replace the equipment, and GETs is not applicable. Addressing congestion on one facility also has a chance to shift the congestion concern to adjacent or nearby facilities which may have previously shown no issues due to the initial bottleneck. Thus, when developing solution concepts, especially DLR, it may be prudent to expand the investigation beyond just the facility that appears as a constraint in the historical market reports.

Furthermore, Minnesota transmission owners have piloted some GETs already including:

- In 2024, GRE partnered with Heimdall Power to deploy DLR technology on 10 transmission lines.
- Xcel has piloted two DLR projects with Heimdall Power in its NSP service territory and its PSCO territory on two transmission lines.
- OTP is working on implementation of Ambient Adjusted Ratings (AARs) on certain facilities, including a facility listed in this report, ahead of MISO’s implementation of real-time AARs under FERC Order 881.
- ITC Midwest is piloting use of AARs on 6 of its transmission lines including one transmission line in its Minnesota footprint.

Future Congestion Forecast Models

Future congestion in the next five years was forecasted by conducting production cost modeling simulations using Hitachi Energy's software PROMOD for the bookend years of 2026 and 2030. PROMOD is an industry standard for simulations of integrated electric generation and transmission markets. The models used as a basis of this study were the MISO Future 1A models developed for the MISO Long Range Transmission Planning (LRTP) Tranche 2.1 transmission planning process. Given these models were initially developed for long range planning and their assumptions were developed in 2022 and 2023, many adjustments were made to bring the model closer to contemporary conditions. These changes included:

- Adjusting retirement dates (especially of coal units) to match the most up-to-date information
- Removing generic future proxy generation resources that were developed as part of MISO's resource expansions process
- Adding planned generation additions that were not known in the 2022/2023 timeframe

These updates resulted in 2026 and 2030 models that are approximate representations of the near future. The validity of these models is confirmed by comparing historical MISO generation capacity data. This comparison is shown in the following table. Data from 2023 and 2024 was taken from the annual fact sheets provided by MISO. All values in the table are in GW.

	MISO 2023	**MISO 2024**	**GETs Model (2026)**	**GETs Model (2030)**
Gas	80.2	80.8	74.1	75.8
Coal	47.8	46.5	34.7	23.9
Wind	30.6	32.3	34.8	38.8
Solar	7.6	16.2	22.1	47.6
Nuclear	13.4	14.1	11.8	11.8
Hydro	7.6	8.1	10.6	10.6
Other[1]	3.8	4.0	11.1	12.6
Total	191	202	199	221

[1] *Other includes diesel, biomass, storage, and demand response*

Planned outages for 2026 across the entire MISO system were also included in the 2026 models. Planned outages were taken from the MISO OATI Open Access Same-Time Information System (OASIS) as of June 26, 2025. Prior outages were not included in the 2030 models given the uncertainty and unavailability of outages that far into the future.

In addition to generation updates, the LRTP Tranche 1 projects were included in the 2030 model. While some LRTP Tranche 1 projects will not be in-service until after 2030, it provides insight into what constraints may increase or reduce in severity after this large portfolio is completed.

It should be noted that PROMOD, as a simulation tool, has perfect foresight of future operating conditions and thus may underestimate congestion compared to historical actuals.

Given that PROMOD is a simulation tool there are some additional caveats regarding any future congestion results.

1. PROMOD tends to underestimate congestion compared to historic conditions given that it simulates system intact and N – 1 conditions only. PROMOD's final dispatch will be most economically optimal while respecting facility ratings under any single N – 1 event included in the simulation. In the real world, both planned and unplanned transmission outages can have a significant impact on congestion and there are generally tens of transmission outages on the MISO system at any time. While the 2026 model does include planned outages, unplanned (also known as forced) outages are not predictable.

2. Some contingencies have real-time operating guides that involve temporary switching or reconfiguration. These operating guides are generally not modeled in PROMOD, and some constraints may show more significant congestion in future simulations than seen in the past. Despite best efforts to develop good models to represent conditions for 2026 and 2030, all future congestion results should not be taken as a guarantee of future occurrence.

3. Finally, PROMOD is a computational intense program as it simulates all 8,760 hours of a year. This means that, unlike standard powerflow simulations, every branch-contingency pair cannot be included in the simulation with the expectation that the model would complete an 8,760 hour simulation in a reasonable amount of time. A subset consisting of only the most likely or significant contingencies are monitored in the simulation numbering in the range of 1,000 to 2,000 contingencies with each contingency definition only enforcing ratings on a handful of other monitored facilities. These contingencies are defined in what is called an "event file". For these models, the original event files developed by MISO as part of the Future 1A models were used and modified to include:
    a. All historically occurring congestion events from 2022 – 2024
    b. Additional constraints identified with internal screening tools as potential congestion concerns

Discussions with GETs Vendors

A requirement from the Commission was for transmission owners to consult with GET vendors to ensure that modeling best practices are considered.[12] Meetings were held with vendors of three different GETs: DLR, APFC, and Topology Optimization. During these meetings, transmission owners learned about modeling these solutions as well as a general overview of the technologies including their applications, costs, and benefits. A summary of each of these discussions is included below.

Dynamic Line Ratings (DLR) – Heimdall Power

Meeting Overview: Transmission owners met with Heimdall Power on August 7, 2025, and discussed DLR technology applications and efficient ways to model the technology when considering future solutions. Transmission owners provided an overview of the MN GETs study, and Heimdall noted parallels to how Great River Energy previously identified DLR candidates in their deployment of the technology in 2024. Heimdall noted that for modelling it is generally sufficient to simply increase a conductor's rating by 10% - 20% to account for additional gains. Even though DLR may frequently provide higher ratings, it is common for any further capacity to be limited by a terminal equipment rating on the facility. In addition, 10% to 20% additional capacity usually resolves most direct and indirect congestion, and DLR provides this conservative gain consistently during all seasons. Discussions on costs provided a general cost estimate of $150k to $300k per line to implement DLR with implementation timelines of an initial two months to set up the infrastructure and mapping of data to a utility's energy management system. After the initial setup, deployment of the sensors to lines can likely be accomplished in weeks.

Advanced Power Flow Control (APFC) – Smart Wires

Meeting Overview: Transmission owners met with Smart Wires on August 11, 2025 to discuss this technology and how to model it in future studies. The discussion included an overview of the MN GETs study provided by the transmission owners followed by an overview of how Smart Wires' APFC technology works to adjust grid impedances to either push or pull power around congestion facilities by using a variable impedance to make a line appear longer or shorter to the overall system. Smart Wires conducts studies to determine an ideal location and range of impedance values starting with powerflow models and then use production cost models to determine economic benefits while ensuring that the adjusted impedance does not shift congestion to other facilities. Implementation timelines for standard sized APFC devices from Smart Wires take between 12 and 18 months to implement but may have more variance depending on the substation footprint. Costs generally range from $10M to $40M depending on the size of the

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[12] See Commission's September 10, 2025 ORDER ESTABLISHING REQUIREMENTS, in Docket No. E999/M-25-99, Order Point 4(h).

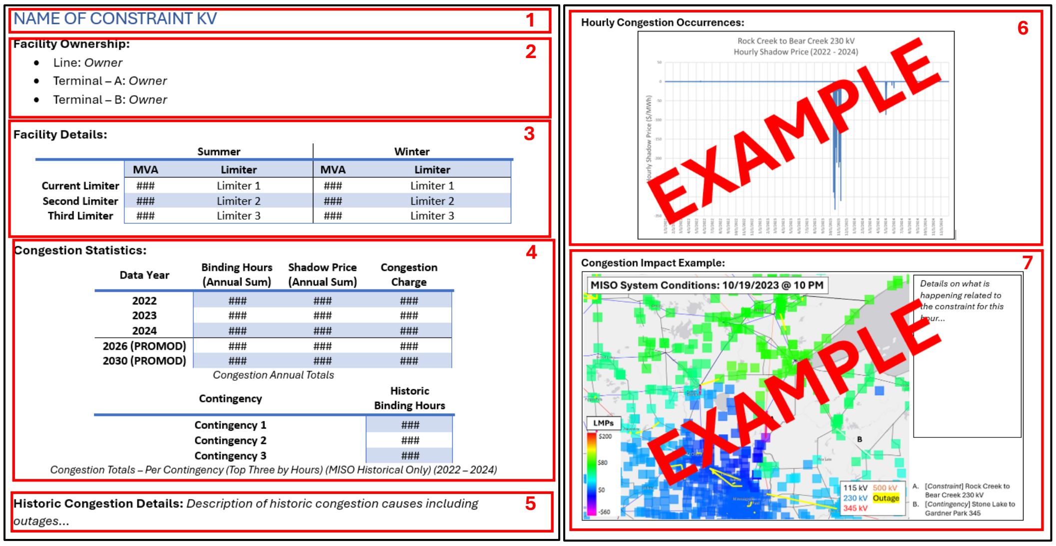
necessary installation (not inclusive of substation expansion if necessary). The technology is scalable, operating from 69 kV up to 500 kV and can be relocated if system conditions change.

Topology Optimization – New Grid

Meeting Overview:
Transmission owners met with NewGrid on August 18, 2025, to discuss how topology optimization software works and its use cases. NewGrid is a topology optimization company. Given one or more constraints that are highly loaded or overloaded, NewGrid's topology optimization software attempts to identify reconfiguration options to relieve the constraints by rerouting power around them, without shifting congestion to other parts of the system. Contingency analysis is executed by the software to ensure that reconfigurations identified are reliable. Inputs to the analysis include power flow cases (e.g., either planning cases or operations state estimator cases). Reconfigurations are generally developed in anticipation of planned outages where there is ample time to develop and analyze a solution to mitigate forecasted congestion. Similarly, topology optimization analysis can be run to inform reconfiguration options for areas that exhibit frequent congestion in operations. New-Grid licenses the software package and also provides a service to mitigate congestion using topology optimization. Timeframes for implementation of system reconfigurations can vary from a couple days to a couple months depending on the complexity of the cases and the duration of the congestion events of interest. Given that topology optimization isn't a physical asset, the costs of implementation are less conclusive; however, NewGrid noted that overall costs have generally been in the single digit percentages of the overall congestion savings.

Template Details

This section provides details on each section of the constraint details template. The information for all constraints follows this template. All congestion data is day-ahead.



NAME OF CONSTRAINT KV 1

Facility Ownership: 2

- Line: *Owner*
- Terminal – A: *Owner*
- Terminal – B: *Owner*

Facility Details: 3

	Summer		Winter	
	MVA	**Limiter**	**MVA**	**Limiter**
Current Limiter	###	Limiter 1	###	Limiter 1
Second Limiter	###	Limiter 2	###	Limiter 2
Third Limiter	###	Limiter 3	###	Limiter 3

Congestion Statistics: 4

Data Year	Binding Hours (Annual Sum)	Shadow Price (Annual Sum)	Congestion Charge
2022	###	###	###
2023	###	###	###
2024	###	###	###
2026 (PROMOD)	###	###	###
2030 (PROMOD)	###	###	###

Congestion Annual Totals

Contingency	Historic Binding Hours
Contingency 1	###
Contingency 2	###
Contingency 3	###

Congestion Totals – Per Contingency (Top Three by Hours) (MISO Historical Only) (2022 – 2024)

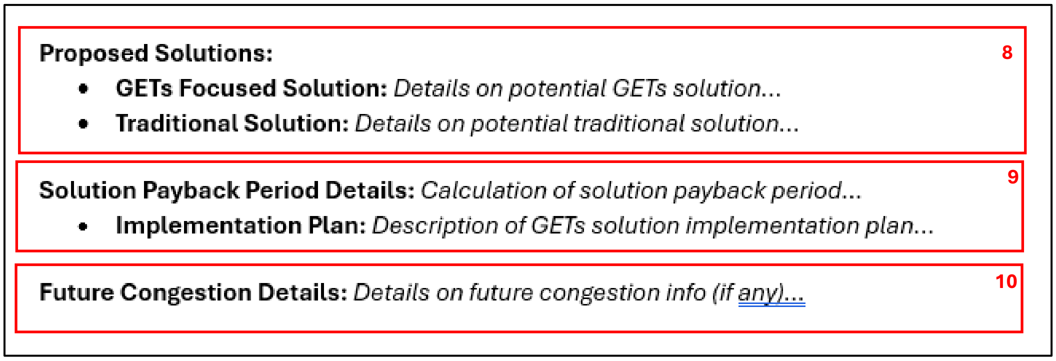
Historic Congestion Details: *Description of historic congestion causes including outages...* 5

Hourly Congestion Occurrences: 6

Congestion Impact Example: 7

Details on what is happening related to the constraint for this hour...

A. [*Constraint*] Rock Creek to Bear Creek 230 kV
B. [*Contingency*] Stone Lake to Gardner Park 345



Proposed Solutions: 8

- **GETs Focused Solution:** *Details on potential GETs solution...*
- **Traditional Solution:** *Details on potential traditional solution...*

Solution Payback Period Details: *Calculation of solution payback period...* 9

- **Implementation Plan:** *Description of GETs solution implementation plan...*

Future Congestion Details: *Details on future congestion info (if any)...* 10

1. **Constraint Name:** Includes an common name of the constraint and the voltage
2. **Facility Ownership:** Identifies the owner(s) of the facility.
3. **Facility Details:** Highlights the current and next two limiting elements
    a. Given that most market constraints appear under contingency conditions the table includes only the emergency ratings (unless otherwise noted).
4. **Congestion Statistics:** Includes two tables summarizing relevant historical and future congestion statistics. All historical values are day-ahead.
    a. **Congestion Annual Totals:** Includes the binding hours, total annual shadow price sum, the total congestion charge, and the FTR adjusted congestion charge for each year
    b. **Congestion Totals – Per Contingency:** Highlights the three-year sum of binding hours for the top three contingencies causing congestion
5. **Historic Congestion Details:** Provides additional details as to the driver of the historic congestion as well as details about pending projects or outage conditions if appropriate

6. **Hourly Congestion Occurrences:** Included here is a chart of the day-ahead hourly shadow price for the constraint from 2022 through 2024. This provides insight into whether the constraint was a persistent problem throughout the years or limited to a discrete timeframe.
7. **Congestion Impact Example:** A constraint can have wide reaching impacts on prices or an isolated effect on a local area. This section includes a map showing the day-ahead prices in the MISO market for a single hour in which the constraint was present. Also present are any known transmission outages for the hour. This provides a reference for where the constraint is geographically as well as the extent of its impact on prices.
    a. The prices are overlaid on a straight-line approximation of the transmission network. Unless the constraint is a sub-100 kV facility, only 100 kV and above facilities are displayed on the map to reduce clutter.
    b. The example hour chosen is generally one in which the constraint had the most severe shadow price (and thus the most severe price impact) and one where other nearby constraints are not present. For most constraints there are many other hours where the price impact is less significant.
8. **Proposed Solutions:** A description for a GETs solution (and if applicable an alternative traditional solution) is provided. This description includes the details of what equipment would be upgraded, the costs, and the additional MVA ratings
9. **Solution Payback Period Details:** Here the payback period for the GETs solution is calculated. If the payback period is less than or equal to five years[13] then the constraint's solution is included in the implementation plans section.
10. **Future Congestion Details:** If the constraint has forecasted congestion in the PROMOD simulations, this section details the driver in the models.

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[13] See Commission's September 10, 2025 ORDER ESTABLISHING REQUIREMENTS, in Docket No. E999/M-25-99, Order Point 4(b).

Pages 19 - 183 of Appendix B discussing individual transmission constraints in the Grid Enhancing Technologies (GETs) Report are marked “NONPUBLIC” and have therefore been omitted pursuant to Minn. R. 7829.0500, subp. 3, the MTO provides the following description of the excised material:

1. Nature of the Material: Appendix B includes descriptions of individual transmission constraints across the transmission grid in Minnesota.

2. Authors: The specific project descriptions were drafted by MTO utilities.

3. Importance: The information in the individual transmission constraints provides details on potential specific project vulnerabilities across the transmission grid in Minnesota.

4. Date the Information was Prepared: The information was prepared throughout 2025.