

STRATEGIC INTEGRATION OF GRID ENHANCING TECHNOLOGIES (GETS) IN TRANSMISSION PLANNING

AN XCEL ENERGY & GRIDLAB WHITEPAPER

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Executive Summary

Xcel Energy operates in a transmission environment characterized by accelerating load growth, increasing penetration of inverter-based resources (IBRs), retiring base load units, expanding interconnection activity for both generation and large loads, and heightened expectations for reliability, resilience, and affordability. These system changes are occurring in parallel with long development timelines for conventional transmission infrastructure driven by constraints in routing, siting, permitting, supply chain, and construction. As a result, Xcel Energy faces a growing need for complementary strategies that can provide near-term capacity relief and operational flexibility while longer-term transmission projects progress through the development pipeline.

Grid enhancing technologies (GETs) provide a class of solutions that can increase the effective utilization, flexibility, and controllability of existing transmission assets. These technologies include advanced conductors, dynamic line ratings (DLRs), advanced power flow controllers (APFCs), and transmission topology optimization (TTO). GETs are not intended to replace traditional transmission expansion. New transmission lines, substations, and other major system rebuilds remain essential to reliably meet long-term load growth, resource integration, and regional transfer capability needs. However, GETs can complement conventional transmission by helping address near-term constraints, unlocking latent capacity, improving asset utilization, and enhancing operational flexibility. GETs can defer the timing or reduce the scope of certain upgrades, providing system benefits while long-lead infrastructure projects are developed.

Xcel Energy's internal assessment of planning and modeling capabilities indicates that some of the GETs can be represented directly in existing steady-state and dynamic planning tools, while others require approximation through adjusted limits, proxy models, and scenario-based analysis. A structured integration strategy is therefore required to ensure that GETs are evaluated rigorously, used appropriately in operations, and institutionalized within Xcel Energy's established planning, operational, and governance processes. Improving transmission utilization through GETs does not mean maximizing average facility loading or reducing required reliability margins. Transmission utilization is dependent on location, time, topology, dispatch, outages, and contingency conditions. GETs can improve utilization of existing transmission facilities where additional capability is available, but unused capability on one facility or under certain operating condition does not necessarily mean that additional transmission capacity is available where and when it is needed to reliably serve generation or load.

This document is intended to serve both as a Planning Engineer's Reference Guide and as an industry thought leadership article on the planning applications of GETs. The document presents a structured methodology for evaluating GET opportunities, synthesizes research-

demonstrated capabilities, captures lessons learned from Xcel Energy and industry implementations, and discusses the underlying reasons for the persistent gap between theoretical benefits reported in the literature and realized field performance. By combining practical planning guidance with industry experience and critical analysis, this document aims to help planners make informed, technically rigorous decisions regarding GETs deployment. This first version is expected to evolve as industry practices mature, additional operational experience is gained, and new technologies emerge.

1 | Purpose and Application of This Guide

This document serves as a planning engineer's reference guide for evaluating grid enhancing technologies (GETs) within the transmission planning alternatives analysis process. It does not establish design standards or replace engineering judgment. Instead, it summarizes the capabilities, limitations, applicability, and implementation considerations of four GETs: advanced conductors, dynamic line ratings (DLR), advanced power flow control (APFC), and transmission topology optimization (TTO).

GETs should be evaluated within the context of specific system needs, planning objectives, operating practices, and study assumptions. Accordingly, this guide emphasizes the use of consistent technical, economic, operational, and reliability criteria when comparing GETs with conventional transmission solutions.

The document intentionally distinguishes between research-demonstrated capabilities and practical utility implementation experience, highlighting both the potential benefits identified in research and the lessons learned from industry and Xcel Energy applications. As planning tools, operational capabilities, regulatory requirements, and industry experience continue to evolve, this guide is expected to be updated accordingly.

2 | Federal Energy Regulatory Commission (FERC) Regulatory Drivers for GETs

Three FERC orders collectively establish complementary requirements that promote the consideration and use of advanced transmission technologies (ATTs) across transmission planning, generator interconnection, and system operations. The requirements differ by process and technology and generally require evaluation or enabling capability rather than deployment of a particular technology in every application. Terminology also varies across regulatory and industry sources: FERC Order No. 1920 [1] uses "transmission switching" for the

broader action of reconfiguring the transmission system, while industry sources [2], [3] use TTO to describe analytical or optimization tools that identify beneficial reconfigurations. In this white paper, TTO refers to the analytical or optimization capability, while "transmission switching" or "reconfiguration" refers to the resulting physical switching action. TTO is a form of transmission switching that uses optimization to identify beneficial transmission-system configurations; however, not all transmission switching involves TTO.

1. Order 1920 [1] requires transmission providers to consider GETs in long-term regional transmission planning. Specifically, the order names DLR, APFC devices, transmission switching, and advanced conductors as four GETs to be evaluated. Studies must evaluate whether GETs can address the same needs more efficiently or cost-effectively than other potential long-term regional transmission facilities. When a GET is selected as, or incorporated into, a long-term regional transmission facilities, its cost may be eligible for regional cost allocation subject to the applicable regional planning entity's selection and cost allocation criteria.
2. Order 2023 [4] reforms the generator interconnection process and requires transmission providers to consider ATTs when evaluating potential network upgrades identified through generator interconnection studies including APFC devices and advanced conductors as solutions. The impact is to broaden how generator interconnection studies evaluate potential solutions to transmission capacity constraints and associated network upgrade needs.
3. Order 881 [5] requires transmission providers to use ambient-adjusted ratings (AARs) that account for forecast ambient air temperature in evaluating near-term transmission service and system operations.

FERC Orders 2023/2023-A and 1920 address overlapping but not identical sets of advanced or alternative transmission technologies. This whitepaper focuses on advanced conductors, DLR, APFC, and TTO because these technologies are principally intended to increase or optimize transmission capability on the existing system. Other technologies identified by FERC, including static synchronous compensators (STATCOMs), static VAR compensators, synchronous condensers, voltage source converters, and tower lifting, may address other transmission needs but are outside the scope of this whitepaper.

3 | Role of GETs Within Xcel Energy's Transmission Planning Framework

Xcel Energy conducts transmission planning through a structured, multi-horizon process that includes local reliability planning, regional coordination, long-term system planning, and interconnection-driven upgrades. This process evaluates system needs based on load forecasts, resource plans, interconnection queues, and reliability performance under a wide range of contingency and future scenario conditions. Traditionally, identified constraints are addressed through conventional solutions such as new transmission lines or new transformers, reconductoring, transformer upgrades, and substation expansion. Xcel Energy comprises four operating companies: Northern States Power Company of Minnesota and Northern States Power Company of Wisconsin (collectively, NSP), Public Service Company of Colorado (PSCo), and Southwestern Public Service Company (SPS). Because these operating companies are parts of different market or non-market structures, some sections will highlight the differences in how GETs apply to the different operating company context.

Under a GETs-influenced planning framework, these conventional solutions remain the foundation of long-term system development. GETs will be incorporated as complementary options during the alternatives analysis phase of planning. **For each identified constraint, transmission planning and system operations engineers evaluate whether GETs can provide near-term relief, defer the timing of conventional upgrades, cost-effectively reduce the scope of physical infrastructure, or improve operational performance while permanent solutions are advanced.**

GETs will be assessed using Xcel Energy's system specific characteristics, planning considerations, and engineering judgment to determine whether they can effectively address identified needs in a manner comparable to the proposed long-term transmission solution. In this context, Xcel Energy may be able to determine early in the evaluation process that certain technologies are or are not suitable for further study on a particular transmission element, or that there may be opportunities for their application as near-term or mid-term solutions. Sections 7 through 10 will cover the details of system characteristics, planning considerations, and engineering judgement that are relevant for the four GETs covered by this document.

This approach helps ensure GETs are evaluated transparently alongside traditional solutions, consistent with Xcel Energy's reliability criteria, capital planning processes, and long-term system development strategy. It also supports a portfolio-based planning philosophy in which operational flexibility, asset utilization, and infrastructure expansion are optimized together rather than treated independently.

3.1 GETs Within Xcel Energy Transmission Planning

For purposes of this guide, GETs are transmission technologies that improve the capacity, visibility, controllability, or utilization of existing transmission infrastructure. The four principal GET families evaluated by Xcel Energy are:

- **Advanced conductors,** which can provide a durable increase in conductor ampacity, subject to structural, clearance, terminal-equipment, constructability, and network limitations
- **DLR,** which vary line ratings based on environmental and conductor conditions, subject to measurement accuracy, validation, communications, operational integration, and availability
- **APFC,** which redirects power from constrained facilities toward paths with available capability
- **TTO,** which evaluates alternate switching configurations that may reduce congestion or overloads while maintaining required system performance

The application and implementation requirements of each GET differ. Advanced conductors are already evaluated through coordination between Xcel Energy's Transmission Planning and Transmission Line Engineering groups when additional transmission capability is needed. DLR and topology optimization require closer integration with operational data, energy management systems (EMS)-quality models, operating procedures, and Transmission Operations. APFC can be represented directly in planning studies but must be evaluated at the network level to ensure that flow redistribution does not create adverse impacts elsewhere.

GETs should not be treated as a single class of interchangeable solutions. Each technology addresses different limitations and provides a different type of capacity:

- Advanced conductors provide **physical thermal capability**, when replacing existing, thermally limited conductors and are most cost-effective when they are able to make use of existing towers
- DLR provides **conditional, weather-dependent thermal capability**
- APFC provides **controllable redistribution of existing network flows**
- TTO provides **topology-dependent operational capability**

A GET should advance only when it addresses the actual limiting condition and its capability is available during the times of system need.

3.2 North American Electric Reliability Corporation (NERC) Compliance and Reliability Risks

GETs do not eliminate Xcel Energy's obligation to comply with applicable NERC reliability standards. A GET may be credited in transmission planning only when its assumed performance

is technically supportable, available under the studied conditions, represented consistently in planning and operating models, and incorporated into approved procedures where operational action is required.

Potential compliance and reliability risks include:

- Assuming a dynamic or conditional rating will be available without sufficient supporting evidence
- Inconsistency among planning, EMS, outage-coordination, and real-time operating models
- Failure to model the most limiting conductor span, terminal equipment, or other series element
- Reliance on sensors, communications, software, or operator action without an approved fallback
- Crediting device setpoints or topology changes that cannot be implemented reliably by Operations
- Failure to evaluate impacts on neighboring facilities or neighboring systems
- Inadequate voltage, stability, dynamic, electromagnetic transient (EMT), short-circuit, or protection analysis
- Treating temporary congestion relief as a permanent solution to a persistent reliability need
- Inadequate documentation of assumptions, availability, corrective actions, and decision authority
- Failure to reassess the solution as forecasts, topology, generation dispatch, or system conditions change

A GET may support a planning alternative when its performance and implementation are appropriately demonstrated. It should not be used to defer conventional reinforcement when dependable performance cannot be demonstrated across the applicable planning events and system conditions.

3.3 Regional Transmission Organization (RTO) and Regional Planning Treatment

RTO and regional planning treatment of GETs varies by tariff, planning process, technology, and regional need. GETs may be evaluated in reliability planning, economic planning, generator interconnection, outage coordination, or operational congestion-management processes. Federal requirements (FERC Orders 1920 and 2023) and state policies increasingly require consideration of advanced conductors, APFC, DLR, and transmission switching, and other alternative transmission technologies within specified transmission planning and interconnection processes. These requirements generally require GETs to be evaluated as

alternatives; they do not require selection of a GET when technical, reliability, operational, or economic analysis does not support it.

RTOs may monitor facility loading, congestion, binding constraints, outage impacts, interface flows, and operational performance, but those measures should not be characterized as a single regional transmission utilization goal unless the relevant tariff or planning process expressly establishes one. Until specific regional planning processes or criteria are established for GETs, each Xcel Energy operating company will evaluate GETs under the decision framework outlined in this whitepaper.

4 | Xcel Energy's Congestion Mitigation Work and the Role of GETs

In organized wholesale market regions, Xcel Energy uses nodal production cost models with public financial transaction data to understand where congestion and curtailment negatively impact the generation production costs for ratepayers. Shadow prices, expressed in $/MW, can be used to identify transmission elements where improvements may have a significant impact on congestion costs and to indicate the marginal value of relieving those constraints. The impact of a particular project can be evaluated through the adjusted production cost (APC) or in reduced curtailment (measured via hours or energy). In organized markets such as Southwest Power Pool (SPP) and Midcontinent Independent System Operator (MISO), conventional projects or GETs may also influence locational marginal prices (LMPs), congestion rents, and transmission congestion rights. These market impacts should be considered when evaluating long-term economic benefits. In areas that are not part of an organized wholesale market, Xcel Energy can also use nodal production cost models to estimate congestion impacts of GETs. While these modeled solutions may not converge on actual congestion being experienced in the system, they can provide helpful directional indications of the impacts of the GET under study.

Congestion mitigation happens across multiple timeframes: reactive to real-time system conditions and historical LMP differentials, proactive in acknowledgment of planned upgrades or outages (example: preparation for long-lasting outages), and in forward-looking planning models. Some congestion on a system is healthy. To operate a system in which no lines ever reach their thermal limits would suggest it is overbuilt beyond economic justification. Similarly, not all curtailment can or should be eliminated; particularly, in high renewable systems, there are many hours when the outputs of renewables exceed the system load. Additionally, some congestion is outage related. If a generator or transmission facility is out for maintenance, it would not be appropriate to design and build transmission solutions to address short-term,

non-repeated congestion. GETs are considered among the suite of possible solutions to address congested facilities, particularly when GETs solutions can be quickly deployed relative to larger infrastructure projects.

Some congestion mitigation is necessarily reactive — for example, if a transformer fails, significantly reducing transfer capacity on a line unexpectedly, financial and operations data reflect the impact to congestion costs. Xcel Energy's operations and planning engineers have a history of accelerating replacement timelines to mitigate the economic cost to customers.

Xcel Energy conducts regular systemic congestion mitigation analysis in which binding elements from previous years are analyzed. When evaluating opportunities to address a congested facility, first the planners identify the limiting element. In some circumstances, 'low-hanging fruit' opportunities to increase the rating for a line can be achieved by upgrading endpoint (substation) equipment, often called terminal equipment. Many projects identified in the 2023 Grid North Partner's congestion relief projects [6] were terminal equipment upgrades. In other instances, larger infrastructure investments or greenfield projects may be required to ensure deliverability of low-cost generation to customers. If the congestion is outage-related and unlikely to reoccur in the future, no solutions are proposed although the congested line is monitored in future congestion reviews.

Future production cost models can also identify regions or connections with expected congestion. Future models and their congestion are evaluated and compared to known system constraints. A model representing the system 5 years from now is more certain than a 20-year out model. Given that transmission infrastructure can take 10 years to build, the 10- and 20-year models can be valuable for identifying cost-reducing opportunities through transmission infrastructure.

5 | Transmission System Utilization and the Role of GETs

Transmission utilization does not have a single universally accepted definition or a single system-wide value. Depending on the purpose of the analysis, utilization may refer to instantaneous or peak loading relative to a facility rating, average loading over a defined period, load factor, hours above selected loading thresholds, congestion frequency, curtailment, available transfer capability, or the extent to which existing infrastructure supports customer demand and regional power transfers. These measures describe different aspects of transmission-system use and should not be treated as interchangeable.

Xcel Energy does not currently use a single transmission utilization percentage as a controlling planning metric. Transmission utilization is specific to location, time, topology, generation

dispatch, load level, facility outages, and contingency conditions. Because power flows follow the electrical characteristics of the interconnected network, a facility that appears lightly loaded under one operating condition may be necessary to serve load, maintain voltage or stability performance, accommodate the loss of another element, support maintenance outages, or preserve restoration capability under another condition.

A meaningful transmission utilization assessment should therefore use a portfolio of measures, which may include:

- Facility loading distributions across representative operating conditions
- Peak loading relative to the applicable facility rating
- Hours above defined loading thresholds
- Loading under applicable planning events and contingency conditions
- Available thermal headroom under normal and contingency conditions
- Frequency and duration of binding transmission constraints
- Congestion, redispatch, and curtailment patterns
- Utilization of parallel paths and interfaces
- Outage, maintenance, and restoration capability
- The extent to which voltage, stability, protection, terminal equipment, or other non-conductor limitations constrain transfers

This whitepaper does not assign a single current utilization value to the Xcel Energy transmission system. Any reported transmission utilization value should identify the applicable facilities, voltage class, rating basis, operating period, direction of flow, treatment of outages and contingencies, and whether the value represents peak loading, average loading, load factor, or another metric. Without this context, a single aggregated percentage could obscure where and when usable transmission capacity is actually available. Congestion costs and Xcel Energy's congestion mitigation approach are discussed separately in Section 4. Congestion cost and physical transmission utilization are related but not equivalent measures.

5.1 Appropriate Use of Transmission Utilization Metrics

Transmission utilization can be a useful diagnostic and planning metric, but it should not be used independently to determine whether the transmission system is efficiently designed or whether additional infrastructure is unnecessary. Higher utilization is not inherently better, and lower utilization does not necessarily indicate overinvestment. Transmission facilities also provide contingency margin, outage capability, operational flexibility, restoration capability, resilience, and capacity for credible future system conditions.

Utilization metrics are most useful when applied to a defined planning question. Examples include identifying facilities that are persistently highly loaded, determining whether a constraint

occurs during a limited number of hours, identifying unused headroom on parallel transmission paths, evaluating whether congestion is recurring or outage-driven, and determining whether a GET could defer or reduce the scope of a conventional transmission upgrade.

The principal risks of treating utilization as a key transmission performance target include:

- Reducing contingency, outage, maintenance, or restoration margin
- Treating conditional or weather-dependent capability as firm capacity
- Masking localized constraints through regional or system-wide averages
- Overlooking voltage, stability, protection, short-circuit, or terminal-equipment limitations
- Mistaking unused thermal capability on one facility for deliverable capacity at a particular substation, transmission path, or load pocket
- Encouraging deferral of infrastructure where the underlying need is persistent or increasing
- Failing to recognize that increasing the rating or utilization of one facility may shift power flows and create constraints elsewhere
- Increasing dependence on operator actions, communications, data, or corrective-action procedures
- Reducing the ability to remove facilities from service for maintenance (operational flexibility)
- Assigning planning credit to capability that may not be available during the conditions driving the transmission need

The existence of unused thermal headroom somewhere on the system, especially when measured based on historical observed system flows, does not establish that firm capacity is available where a customer seeks service or where a reliability need exists. DLR and certain other GETs may reveal additional capability that is conditionally available, but use of that capability in transmission planning requires an approved and auditable method for determining the amount that can be relied upon during applicable peak, outage, and contingency conditions. Xcel Energy's current planning models, processes, and data infrastructure are not yet broadly configured for the hourly time-series analysis that such determinations would require.

5.2 Relationship to Reliability and Stressed-Condition Planning

A greater focus on transmission utilization should not mean moving away from reliability-based or stressed-condition planning. Utilization analysis should supplement, rather than replace, evaluation under applicable NERC Transmission Planning (TPL) performance requirements, regional planning criteria, local planning criteria, interconnection requirements, and operating obligations.

Traditional transmission planning studies evaluate selected system conditions and applicable planning events to determine whether the system meets defined performance requirements.

Time-series and probabilistic analyses can provide additional information regarding the frequency, duration, timing, and operating context of a transmission constraint. However, the frequency of an event does not by itself determine its consequence. An infrequent condition may still require mitigation if inadequate system performance could result in instability, cascading, uncontrolled separation, voltage collapse, or unacceptable loss of load.

A transmission utilization framework should therefore preserve three complementary layers of analysis:

1. **Standards-based reliability analysis**, demonstrating compliance with applicable planning requirements
2. **Time-series and scenario analysis**, evaluating how frequently constraints occur and whether GET capability is available during those periods
3. **Risk and consequence analysis**, determining whether conditional capacity, corrective action, or operational intervention is sufficiently dependable for the identified need

The recommended evolution is not from "worst-case planning" to "average-case planning." It is toward *multi-dimensional transmission planning* that combines deterministic reliability analysis with time-series, probabilistic, economic, and risk-based information. Average or annual utilization should never be used to override an applicable reliability requirement.

5.3 Vision for Measuring and Improving Transmission Utilization

Xcel Energy's objective should not be to maximize transmission utilization as an independent target. The objective should be to improve the reliable, affordable, and sustainable use of the transmission system while preserving required reliability margins, operational flexibility, maintainability, resilience, and the ability to accommodate system growth.

In the near term, Xcel Energy might propose the following:

- Establish consistent definitions for peak loading, average loading, load factor, congestion, curtailment, conditional capacity, and firm planning capability
- Develop facility- and corridor-level utilization profiles rather than relying on a system-wide average
- Distinguish conductor ampacity from facility rating, deliverability, interface capability, and system transfer capability
- Complete AAR implementation and use the resulting experience as the baseline for evaluating incremental DLR value
- Continue screening advanced conductors during transmission alternatives analysis.
- Evaluate APFC where constraints result from uneven loading across parallel paths with available headroom
- Develop an appropriate TTO pilot jointly with Transmission Operations

- Expand time-series study capabilities to evaluate hourly loading, weather, outages, generation dispatch, topology, and GET availability
- Document not only where GETs are selected, but also where they are rejected and why
- Establish validation, fallback, data-quality, maintenance, cybersecurity, and operating requirements before assigning firm planning credit to operationally dependent GETs

In the longer term, approved GET representations might be incorporated into transmission planning models, production cost analysis, alternatives analysis, operational systems, project development, and capital governance, as described in this document. The desired end state is a portfolio-based planning framework that selects among GETs, conventional upgrades, new transmission, storage, and other non-wire alternatives based on the nature, location, duration, and persistence of the identified transmission need.

6 | Relationship Between GETs and Conventional Transmission Expansion

GETs are not substitutes for long-term transmission expansion. In many cases, load growth, resource integration, and regional transfer needs will ultimately require new transmission facilities and major rebuilds. GETs cannot eliminate the need for these investments. Instead, GETs provide a complementary set of tools that improve system performance in the near- to medium-term (1-5 years) and enhance the effectiveness of existing assets.

In practice, GETs may be used to manage congestion and reliability risks while conventional projects progress through routing, permitting, and construction. GETs may also reduce the scale of certain upgrades by alleviating localized constraints, thereby allowing more targeted conventional investments. In some cases, GETs may serve as interim solutions that bridge the gap between identification of a need and in-service of a major transmission project. This flexibility can also support capital planning by allowing modest, targeted investments that maintain reliability while providing additional schedule and budget flexibility for larger transmission projects. In certain cases, GETs can defer project timing, phase investments, or optimize capital spending without compromising system performance or reliability.

This complementary role aligns with Xcel Energy's planning philosophy of balancing near-term operational needs with long-term reliable infrastructure development. GETs can provide flexibility and adaptability within this framework, allowing Xcel Energy to respond to changing system conditions without compromising long-term system adequacy.

7 | Advanced Conductors for Capacity Expansion Within Existing Rights-of-Way (ROW)

7.1 Research-Implied Capabilities

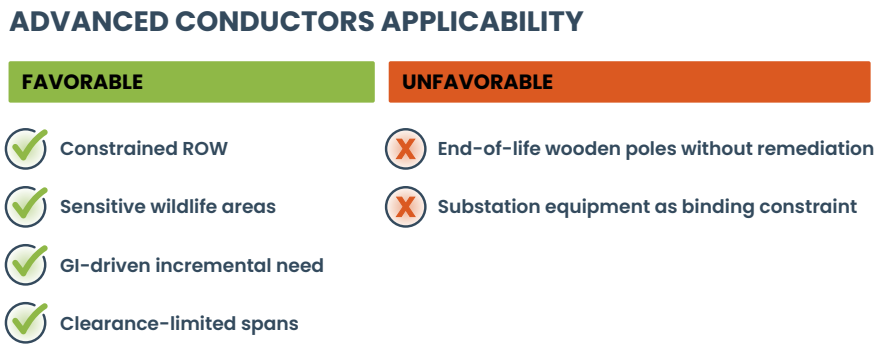
For clarity, this section distinguishes between thermal capacity, transmission capacity, and structural limitations. Thermal capacity (or ampacity) refers to the maximum current a conductor can carry while remaining within allowable temperature and clearance limits. Transmission capacity refers to the amount of electrical power that can be transferred across a transmission corridor and may be limited by thermal, voltage, stability, or other system constraints. Structural limitations refer to physical constraints associated with towers, poles, foundations, spans, hardware, and required conductor operational and safety clearances.

Advanced conductors are a mature GET designed to increase the thermal and transmission capacity of overhead transmission lines by enabling sustained operation at elevated conductor temperatures, typically above 150°C, while maintaining required electrical clearances and mechanical performance. These technologies include both non-proprietary high-temperature conductors and proprietary composite-core and metallic-matrix core designs. Key enabling features include reduced thermal expansion, improved high-temperature material performance, and, in some designs, reduced conductor weight and installed tension.

Advanced conductors increase transmission capacity primarily through reconductoring existing lines, allowing significant increases in current-carrying capability within existing ROW. Industry experience indicates that, for thermally limited ac transmission lines, particularly short-length corridors (approximately 10-30 miles) and medium-length corridors (approximately 30-100 miles), advanced conductors can provide ampacity increases on the order of 5% to 50%, depending on corridor geometry, clearance constraints, and conductor technology selection. This enables meaningful capacity expansion in corridors where new line construction, structure replacement, or ROW expansion would be difficult, costly, or time-consuming. Due to their cost premium compared to traditional conductor types, advanced conductors are not typically the best solution for deployment on new transmission lines that do not face similar ROW or space constraints. Figure 1 summarizes the applicability of advanced conductors for different applications.

FIGURE 1.

Summary of considerations for selecting advanced conductors



A distinguishing benefit of advanced conductors is their ability to achieve higher operating temperatures while maintaining equivalent sag relative to conventional aluminum conductor steel-reinforced designs. This allows utilities to address clearance-limited constraints and structural bottlenecks without widespread structure replacement in many applications. In practice, advanced conductors have been deployed to relieve substation and corridor constraints under which traditional reconductoring would have required extensive structure reinforcement or full corridor rebuilds, thereby reducing construction complexity and outage durations.

While advanced conductors provide substantial capacity benefits, industry experience also highlights important lifecycle and risk considerations. Proprietary advanced conductor options typically carry material costs on the order of 2.5 to 5 times those of standard conductors. In addition, long-term thermal and mechanical performance, including vibration behavior, ice loading response, and core inspection methods, are still being characterized as field experience expands. Historical deployments indicate that a significant fraction of failures have been associated with improper installation, underscoring the importance of specialized construction procedures, contractor training, and rigorous procurement specifications. Table 1 summarizes the key risks and associated engineering controls for advanced conductor applications.

TABLE 1. Summary of lifecycle considerations for advanced conductors

RISK CATEGORY	ENGINEERING CONTROL
Long-term thermal aging at elevated operating temperature	Conductor-specific thermal model; periodic inspection intervals per design standard
Vibration and galloping under ice/wind loading	Specialized vibration damper specification; fatigue analysis for critical spans
Installation quality — significant fraction of historical failures are installation-related	Contractor training and qualification; rigorous procurement specification; construction QA/QC protocol

A summary of vendor-reported performance improvements for advanced conductors is presented in Table 2. These performance improvements must be verified through utility planning studies to generate defensible planning values for each installation.

TABLE 2. Vendor-reported performance ranges for advanced conductors [10]

PERFORMANCE METRIC	VENDOR RANGE	UTILITY ACTION REQUIRED
Operating capacity increase	50–100%	Validate with site-specific thermal model
Thermal sag reduction	~50%	Verify clearance margins at critical spans
Conductor resistance reduction	~30%	Update R, X parameters in PSSE/PSLF/TARA
Line loss reduction	Up to 40%	Confirm in PROMOD production cost model
Indicative process duration	8–24 months	Validate against actual permitting schedule

Note: All ranges are vendor-reported and require utility planning studies to determine defensible value.

For these reasons, deployment of advanced conductors at Xcel Energy is supported by detailed structural and clearance assessments, validated installation practices, and alignment with emerging industry specifications and standards. When paired with other GETs such as DLR, advanced conductors enable both structural and ambient-driven capacity increases, maximizing utilization of existing corridors across a wide range of operating conditions. This combined approach allows Xcel Energy to extend corridor life, defer major rebuilds, and enhance long-term asset performance while maintaining required reliability and safety margins.

7.2 Xcel Energy and Industry Experience with Advanced Conductors

For Xcel Energy, advanced conductors are particularly well-suited for short, constrained corridors, particularly in urban areas with limited ROW, where opportunities for new routes, voltage upgrades, or significant structural modifications may be limited. In these applications, advanced conductors can increase ampacity while potentially minimizing structural modifications. They may also be beneficial for short- to intermediate-length line uprates, including local 345 kV applications, where existing structures and ROW can be reused, provided structure replacement is not otherwise required due to ageing or applicable code requirements. However, advanced conductors may offer less benefit for longer regional extra high voltage (EHV) lines, particularly 765 kV lines, where conductor configurations may be driven by corona and surge impedance loading considerations rather than thermal limits.

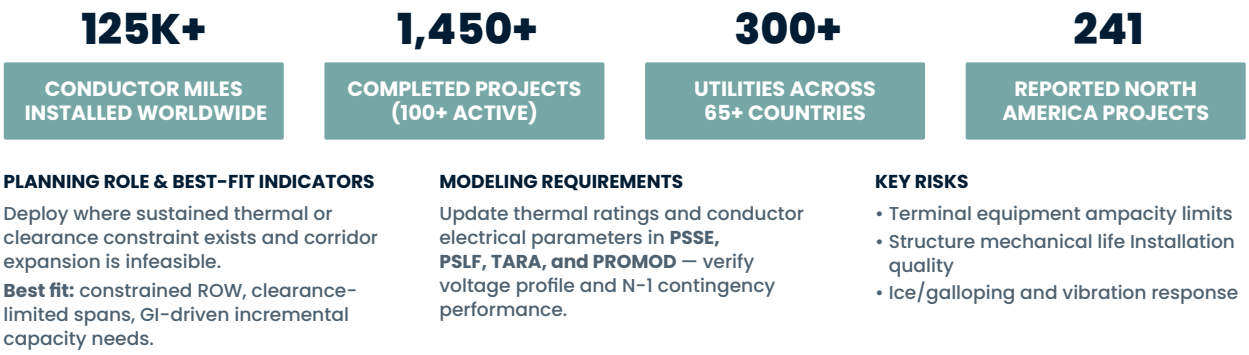
These technologies integrate naturally into steady-state planning workflows through updated conductor electrical parameters and thermal ratings, allowing engineers to directly quantify ampacity increases, post-contingency performance, and voltage impacts using standard power flow and contingency analysis tools. Quantitative values in this guide are classified by evidence source. Vendor-reported and research-demonstrated capabilities are not assumed to constitute transmission planning-creditable values. Transmission Planning credit requires project-specific validation, applicable engineering review, and acceptance through established planning and operating processes.

Xcel Energy has also evaluated advanced conductor technologies as part of major transmission development projects, including the Colorado Power Pathway project and for upgrades in the Denver metro area. As part of that effort, advanced conductor options were assessed as potential alternatives for increasing transmission capacity while minimizing additional right-of-way requirements. These evaluations highlighted the importance of considering not only thermal-capacity benefits, but also structural limitations, constructability, installation requirements, lifecycle costs, and long-term asset performance when determining project applicability.

Advanced conductors have been adopted widely across the globe (see Figure 2). Evaluating their effectiveness in planning studies requires modeling updated thermal ratings and conductor electrical parameters in power flow and nodal production cost models. The key risks associated with advanced conductors are limits on terminal equipment ampacity, mechanical life of supporting structures, installation quality, and ice/galloping and vibration response.

FIGURE 2.

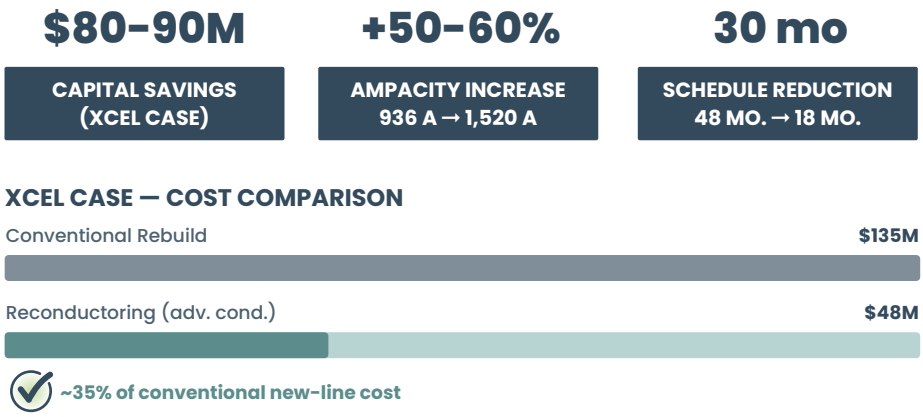
Technological maturity of advanced conductors (global deployment evidence) and summary of planning considerations [7] [8] [9]



Xcel Energy first installed advanced conductors in 2005 and has additional projects approved to reconductor lines using advanced conductors in the next few years. The new projects are driven by generation interconnection, where marginal additional capacity is needed. As noted above, Xcel Energy has primarily seen value for reconductoring existing lines with advanced conductors in sensitive wildlife protected areas where it is difficult to expand ROW, but additional transmission capacity is needed. When planning engineers identify an opportunity for reconductoring with advanced conductors, engineering designers must validate that the physical structures have the capacity and extended lifespan to make a reconductoring project appropriate. If there are old wooden poles near their end of life, simply reconductoring with advanced conductors is not structurally advised. In cases where these criteria are met, Figure 3 shows the possible benefits of adopting advanced conductors as the solution.

FIGURE 3.

Xcel real-world example demonstrates the value of advanced conductors, when appropriately installed



Selection between advanced conductors and Xcel Energy's standard of aluminum conductor steel supported (ACSS) or aluminum conductor steel-reinforced (ACSR) conductor should be based on the incremental ampacity benefit relative to the total installed cost and the physical capability of the existing line. Advanced conductors may provide additional capacity beyond ACSS, but that benefit is most compelling when the existing structures, particularly steel poles, foundations, hardware, and clearances, can accommodate the conductor without extensive modification. If substantial structural replacement is required, the incremental capacity benefit may not justify the additional conductor and construction cost relative to a standard conductor solution. Accordingly, conductor selection should be supported by a project-specific comparison of required ampacity, conductor and installation cost, structural adequacy, remaining asset life, terminal-equipment limitations, constructability, and expected long-term system need. In RTO regions where new transmission projects may be competitively solicited, project-development strategy can create an additional consideration. A developer may initially propose the conductor configuration needed to satisfy the request for proposal (RFP) requirements and maintain a competitive project cost, even when planning analysis indicates that a higher-capacity conductor could provide greater long-term optionality. If additional capacity is subsequently required, reconductoring with advanced conductors may then be pursued as a noncompetitive upgrade to the incumbent facility. This sequencing may be commercially rational, but it can differ from the technically preferred long-term design. Engineers should therefore clearly document both the lifecycle-optimal technical alternative and the competitively driven project alternative so that decision-makers understand the potential cost, outage, and constructability implications of a later reconductoring project.

Given more than 20 years of experience with advanced conductors on the Xcel Energy system, advanced conductors are the simplest GET to incorporate due to seamless integration with planning tools and operational expectations. There is still an opportunity within Xcel Energy to integrate advanced conductors within the "standards" for our construction design engineers and contractors, to facilitate cost-benefit considerations at the design engineering stage and not just during the planning process.

8 | DLRs and Risk-Based Capacity Utilization

8.1 Research-Implied Capabilities

DLRs replace fixed static thermal ratings with ratings that reflect real-time and forecasted ambient conditions, including wind speed, ambient temperature, and solar radiation. By accounting for actual heat dissipation capability, DLR enables more accurate representation of transmission line thermal limits and frequently, but not always, reveals latent capacity that is not captured under traditional static or seasonal assumptions. With today's technology, it is very difficult to accurately measure real-time wind speed, air temperature, and solar radiation effects along every span and at every structure of a transmission line, and to determine which segments of the line become limiting as these conditions vary dramatically along miles of varying terrain. DLR may also result in more conservative ratings at times when the traditional ratings methodologies assumptions for wind speed are more aggressive than ambient conditions. When DLR enables increased ratings, this enhanced utilization can reduce congestion, increase transfer capability, and improve near-term system flexibility while maintaining applicable reliability requirements. However, it should be noted that increased thermal ratings do not necessarily result in equivalent increases in deliverability, Available Flowgate Capability, or transmission service capability. Additional constraints including voltage, stability, and downstream thermal limitations may remain binding.

Because DLR values are weather-dependent and vary over short time horizons, leading industry practice incorporates DLR into planning and operations using risk-based and probabilistic methodologies. Rather than assuming full dynamic capability, utilities and regional planning entities might adopt capped or probabilistic DLR values based on defined availability thresholds within planning models. For example, planning engineers may credit only the DLR capability that is available a specified percentage of the time (e.g., ratings available 95–99% of the time) rather than relying on the maximum rating achievable under ideal weather conditions. These capped values are derived from historical weather data, corridor-specific thermal modeling, and probabilistic analysis to reflect the percentage of time that enhanced ratings are expected to be available. This approach provides a transparent mechanism to balance incremental capacity benefits against operational uncertainty and availability risk.

Sustainable DLR implementation requires attention to lifecycle and operational considerations, including sensor accuracy and calibration, data latency and quality assurance, communications reliability, cybersecurity, maintenance practices, and long-term asset management. Technology selection, vendor qualification, and system architecture must be aligned with operational requirements and regulatory expectations to ensure that DLR-derived capacity is reliable, auditable, and defensible in planning and operational applications.

DLRs are not intended to replace conventional transmission expansion. Rather, they are applied as a supplemental GET to improve utilization of existing assets, enhance operational flexibility,

and provide near-term capacity relief while long-lead transmission infrastructure is developed. Note that DLRs can be targeted deployments on specific transmission infrastructure and can co-exist within a system where other elements have AAR or traditional static ratings. When embedded within formal planning methodologies, operational procedures, and governance processes, DLR supports more accurate transmission utilization and aligns with evolving federal and regional expectations for advanced line rating practices.

8.2 Xcel Energy and Industry Experience with DLR

Xcel Energy, like many other utilities, is in the process of assessing the potential for DLR systems to improve the accuracy of facility ratings. DLR systems purport to provide transmission line ratings that more accurately reflect the environmental conditions at the specific location and time of interest, as compared to seasonal ratings, which rely on assumed conditions, to improve rating accuracy. To do this, DLR systems use forecasted regional weather data from weather data services. Some vendors further enhance the forecasted information with historical field measurements, other available datasets, and computational methods. However, it is very difficult to accurately predict the localized wind speed and wind direction across the length of a transmission line for a given time period. For example, abrupt and significant changes in wind speed and direction are common, and ground terrain and other obstructions add to the complexity of predicting wind behavior. Therefore, implementing practical DLR systems to produce accurate ratings for a full transmission line that account for localized variations is challenging.

Xcel Energy is interested in and engaged with DLR technology and has become an industry leader in evaluating DLR systems. Xcel Energy executed its first DLR deployment in the 1990s, and its second in 2021. In 2023, Xcel Energy initiated its most recent pilot by installing five more DLR systems on two transmission lines (one in Minnesota and one in Colorado). Xcel Energy has also engaged DLR experts from Electric Power Research Institute (EPRI) and EDM International, Inc. (EDM) to provide independent technical support for the evaluation of these DLR vendor installations. The support from EPRI and EDM includes the deployment of weather sensing equipment along the monitored transmission lines and the use of the measurements from these weather sensors to inform and support the comparative analysis of vendor performance and rating methodologies. In total, 43 pieces of commercial rating equipment were installed. Initial results of Xcel Energy's 2023 pilot program show both the potential and the risks of applying commercially available DLR systems and technology.

Based on evaluations of the data produced by the pilot installations to date, Xcel Energy has not been able to prove the ratings produced by these systems are sufficiently accurate to allow Xcel Energy to meet its obligation to provide safe and reliable service.

This preliminary conclusion is supported by the status of DLR industry standards at this time and the relatively low installation rate across North America. For example, there is no industry

performance standard for DLR systems that specifies DLR accuracy requirements, and there is no standard validation methodology for comparing the DLRs from different vendors.

Xcel Energy has not yet adopted a standardized methodology for establishing transmission planning-creditable DLR values. Any future planning credit would require validated time-series data, an approved statistical methodology, defined confidence and fallback criteria, and coordination with Transmission Operations regarding the ratings that can be relied upon under relevant system conditions. For example, appropriate fallback for DLR would be seasonal or AAR ratings, inclusive of any emergency ratings.

For AAR and DLR, Xcel Energy sees their strongest application in system operations and congestion management. To the extent that additional capacity is available under favorable ambient conditions, AAR and DLR can provide operators with additional tools to reduce congestion and mitigate potential reliability issues during extreme conditions that are not normally planned for. AAR and DLR may also have potential applications in economic planning, particularly for congestion during off-peak hours, using probabilistic methods such as Monte Carlo simulation. This would require that economic modeling tool vendors implement these probabilistic methods for AAR and DLR.

For reliability planning, however, static ratings may remain appropriate because real-time information regarding future ambient conditions is not available in the planning horizon. Additional capacity indicated by AAR or DLR may be available during some hours but not others. Relying on this additional capacity in reliability planning could result in less transmission expansion while also reducing the additional margin otherwise available to system operators during extreme conditions. If the additional capacity assumed in planning is not available during certain operating hours, there is also a risk that the system could be underbuilt. Another option for reliability planning may be the use of additional static rating sets that distinguish between seasonal daytime and nighttime conditions. This approach could recognize additional capacity during periods with lower ambient temperatures and no solar radiation without relying on forecasts of future ambient conditions. However, this implementation may require modifications to planning software and energy management systems.

Xcel Energy intends to continue its engagement with DLR vendors and industry partners to evaluate ongoing advancements in DLR technology and remain informed of emerging industry standards and best practices. Xcel is committed to continue developing its approach to DLR implementation as confidence in the accuracy and reliability of DLRs increases and as beneficial use cases are identified.

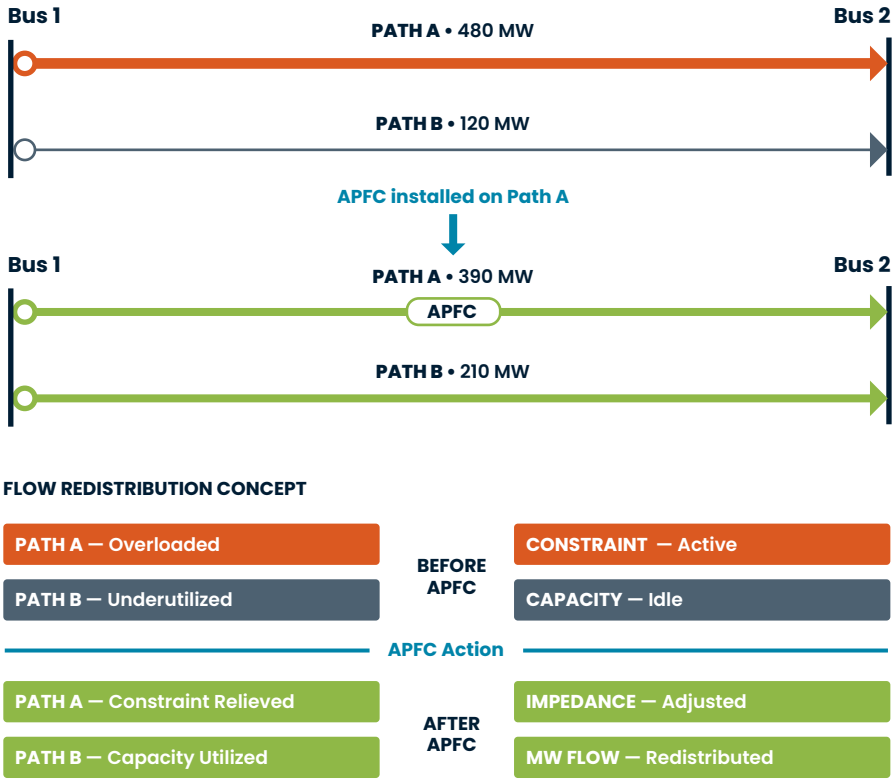
9 | APFC and Controllable Network Utilization

9.1 Research-Implied Capabilities

APFC technologies are power electronic–based devices that actively modify real power flows on transmission lines without requiring changes to generator dispatch or network topology. By injecting controllable series voltage or modifying effective line impedance, APFC devices enable engineers and operators to redirect power from constrained facilities to parallel paths with available capacity (see Figure 4). This capability improves utilization of existing transmission assets and provides a flexible alternative to capital-intensive congestion mitigation measures (i.e. new lines or transformers).

FIGURE 4.

Illustration of flow redistribution concept using APFC



Compared to traditional power flow control technologies such as phase-shifting transformers, fixed series capacitors, and series reactors, APFC devices can provide fast, continuous adjustable control without reliance on electromechanical components. This allows rapid response to changing system conditions, smooth control action, and virtually unlimited operating cycles without mechanical wear. Note, most real-world deployments of APFC do not use autonomous adjustments (see next section). In addition to congestion management, certain APFC implementations can provide dynamic system services, including enhancing transient stability and damping power oscillations through effective impedance modulation on critical tie lines.



Sonnentag Center near the University of Wisconsin–Eau Claire campus. Credit: Xcel Energy

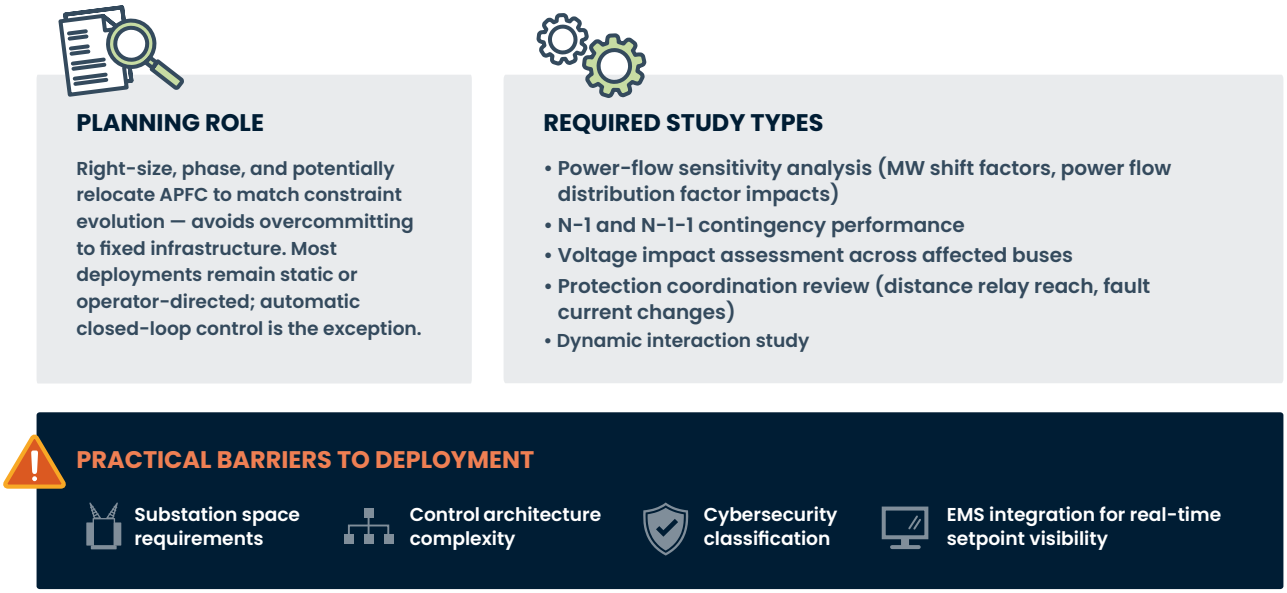
For applications where a fixed level of flow redistribution is sufficient, fixed series compensation may also provide a practical and potentially lower-cost alternative to APFC.

Recent commercial deployments demonstrate that modular static synchronous series compensator technologies, including distributed and scalable series devices, can be flexibly deployed within substations or distributed across multiple substations along a corridor (with the requirement that space is available at the candidate substations). These modular architectures allow solutions to be right-sized for specific constraints and expanded or relocated over time as system needs evolve. This adaptability supports phased deployment strategies and reduces the risk of overbuilding compared to large, bespoke power flow control installations.

APFC technologies have been applied to a broad set of use cases, including targeted congestion reduction, mitigation of unscheduled or loop flows, enforcement of contractual flow paths, and facilitation of renewable resource integration by unlocking latent transmission capacity [11], [12]. They have also been used as interim solutions to maintain reliability during major transmission construction activities and to provide adaptive expansion capability where long-lead infrastructure projects are delayed. In many applications, APFC deployments have complemented other GETs, such as DLRs and TTO, to further increase system flexibility and asset utilization [13], [14].

For Xcel Energy, APFC can be evaluated as an option during alternatives analysis to address deliverability constraints, recurring congestion, and parallel path loading issues. In planning studies, APFC devices can be represented in steady-state power flow models to assess congestion relief, voltage impacts, and contingency performance. However, because APFC devices introduce fast-acting power electronic controls, corridors with high inverter-based resource penetration or sensitive dynamic characteristics require targeted dynamic and EMT-level studies to evaluate control interactions, protection coordination, and system stability impacts. Figure 5 includes a summary of the required study types prior to selecting an APFC solution.

FIGURE 5. APFC planning considerations, study requirements, and deployment barriers



Successful APFC deployment also requires careful integration into operational and asset management processes. This includes development of operating strategies for multiple devices in meshed networks, cybersecurity and communications assessments, EMS integration, and establishment of maintenance and lifecycle management practices. Figure 5 summarizes these practical barriers to deployment — none are insurmountable — but must be considered for a deployment to be successful. A structured planning and governance framework ensures that APFC deployments are supported by rigorous technical validation, cost-benefit analysis, and alignment with operational procedures and market considerations.

APFC is not intended to replace conventional transmission expansion. Rather, it serves as a supportive GET that enhances controllability, improves utilization of existing assets, and provides near-term congestion relief and operational flexibility while long-term transmission infrastructure is developed. When institutionalized within planning, operations, and governance processes, APFC becomes a strategic tool to improve reliability, support resource integration, and optimize transmission system performance.

9.2 Xcel Energy and Industry Experience with APFC

As of Fall 2026, most publicly shared deployments of APFC are operating the devices in a static position, rather than with automatic adjustments. While the devices can be used to respond to real-time conditions, most control room operators do not yet trust them to autonomously adjust their operating state. Even if an APFC is statically deployed, the ability to change the configuration later in response to changing grid topology or power flow congestion changes could provide value.

Industry experience and feedback indicate that APFC devices such as static synchronous series compensators may be particularly beneficial on parallel transmission paths where lower-capacity lines reach their limits while substantial unused capacity remains on higher-capacity parallel lines. The continuous adjustability of these devices, compared with the discrete taps associated with conventional phase-shifting transformers, may provide additional operational flexibility. Accordingly, APFC devices may also warrant consideration when existing phase-shifting transformers require replacement, provided the APFC alternative is technically and economically viable.

There is space for larger industry consensus and collaboration with control room operators to identify needed risk mitigation measures to develop operator confidence in autonomous control by APFC devices.

One additional constraint is the physical space available within substations to deploy the APFC technologies. APFC equipment would be most beneficial in a modular, moveable manner, but in some substations where APFC could be beneficial for the power system, physical space limitations within the substation may drive towards the use of a traditional phase shifter over the APFC.

Xcel Energy's lack of deployment of APFC to date does not reflect an unwillingness to integrate this technology. Xcel Energy recently completed a study in the PSCo footprint which found that APFC sufficiently reduced loading on a circuit, but the redirected flows caused overloads on other circuits. This is an example of the core system-level interaction risk that must be modeled and fully studied before deployment. In our market regions of SPP and MISO, redirected flows may impact facilities owned by neighboring transmission owners. Therefore, APFC evaluations should include regional coordination studies to assess external congestion and reliability impacts.

Table 3 summarizes the use cases for APFC where Xcel Energy sees possible value.

TABLE 3. Potential use cases for APFC

USE CASE	RTO / ISO / UTILITY CONTEXT
Loop flow management and unscheduled flow mitigation	Some ISO / RTO footprints
Parallel path loading enforcement and contractual flow path control	Meshed network corridors
Interim congestion relief during major transmission construction outages	Bridge solution during construction

Xcel Energy's path to a standardized APFC implementation is shown in Figure 6. For any application of APFC, the first step is to identify binding congestion or thermal overloads on the candidate lines. The second step is to perform an alternatives analysis, comparing APFC versus phase-shifting transformers versus a conventional upgrade. This must be performed over the asset lifecycle and should account for the power electronics maintenance and lifecycle costs. Next, the project must pass through Xcel Energy's standard transmission governance framework. In line with most installations, Xcel Energy would expect to first deploy the APFC in static mode in a location where the constraint and impacts are well-understood. Finally, once operating confidence is built, the installation could shift to automatic controls.

FIGURE 6.

Five-step APFC implementation path

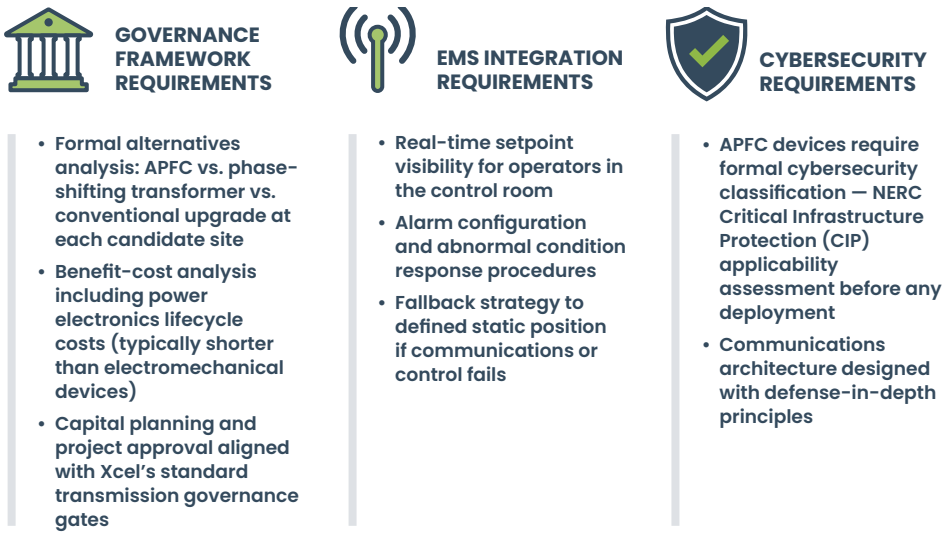
1. **Constraint Identification**
   Identify binding congestion or thermal overloads on candidate lines requiring controllable flow redistribution
2. **Alternatives Analysis**
   Formal comparison: APFC vs. phase-shifting transformer vs. conventional upgrade, including power electronics lifecycle costs
3. **Governance Gate**
   Capital planning and project approval through Xcel's standard transmission governance framework
4. **Pilot Static Deployment**
   Start with static position at a well-understood constraint — build reliability evidence before progressing to operator-directed control
5. **Expand to Operator-Directed Control**
   Modular design enables relocation as constraints migrate; autonomous mode contingent on sustained operator confidence

With this implementation path, there are several best practices that should be established (see Figure 7) around governance, real-time integration, and cybersecurity. The requirements for governance are covered in the study and implementation path. Set-point visibility, alarming, and a communication failure strategy are required for real-time integration. Any communications and controls for the APFC will need to be established in line with formal cybersecurity classification and protection.



FIGURE 7.

APFC governance, EMS integration, and cybersecurity requirements



10 | TTO and Operational Flexibility

10.1 Research-Implied Capabilities

TTO is an advanced software-enabled capability that identifies reliable, lower-cost transmission network configurations by systematically opening and closing circuit breakers at substations. Unlike traditional manual transmission switching practices, which are typically based on predefined operating guides or operator experience, TTO uses optimization algorithms to search across a large space of possible network configurations to identify reconfigurations that reduce congestion, improve post-contingency performance, and lower overall system operating costs while maintaining all applicable reliability constraints.

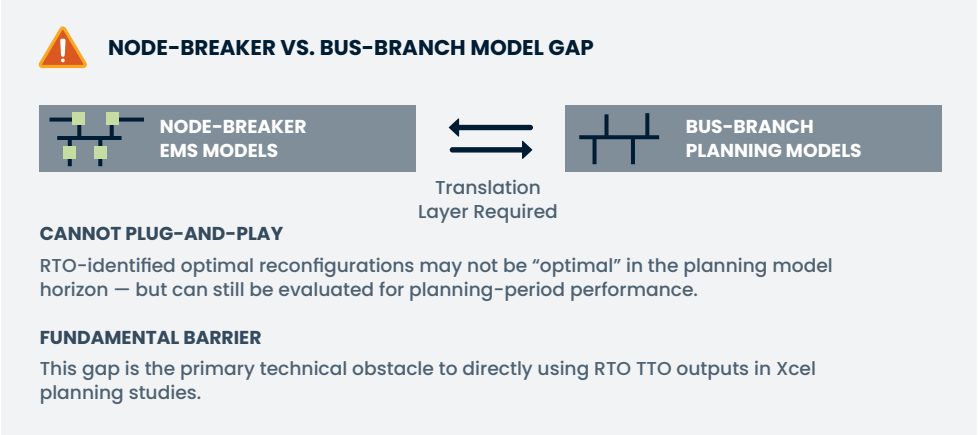
Industry experience demonstrates that TTO can provide material congestion relief and economic benefits by optimizing the use of existing transmission assets [15], [16]. RTOs and ISOs have implemented formalized reconfiguration processes to evaluate topology changes as a complement to generation redispatch and conventional transmission upgrades. For example, recent implementations within the MISO footprint have shown that optimized reconfiguration can reduce congestion costs by a significant percentage on binding constraints and increase effective transfer capability on critical interfaces while longer-term transmission expansion projects are developed [17], [18].

A fundamental distinction between traditional transmission switching and TTO is the systematic, optimization-based nature of TTO. While transmission switching typically involves a limited set of predefined breaker actions for specific operating conditions, TTO evaluates multiple potential reconfiguration combinations using security-constrained technical and economic criteria. This enables identification of repeatable, high-value switching strategies that provide persistent benefits across a range of operating conditions rather than ad hoc

or case-specific remedial actions. However, TTO requires node-breaker models to evaluate possible reconfigurations, and most planning models use bus-branch models (see Figure 8). As a result, practical implementation of TTO typically relies on EMS-quality node-breaker models capable of representing breaker-level switching actions. Regional operators such as SPP have implemented topology optimization tools using operational node-breaker models to identify candidate reconfigurations. These candidate switching actions can then be evaluated within planning models to assess their performance across longer-term planning scenarios. If an operational model, which typically uses node-breaker representation, can be used to identify candidate reconfiguration options, the performance in a planning model could be evaluated. In this case, the reconfiguration may not be "optimal" in the planning horizon.

FIGURE 8.

Node-breaker versus bus-branch model gap



For Xcel Energy, formalizing TTO within transmission planning workflows would allow identification of corridors and substations where repeatable topology configurations can reliably mitigate overloads, reduce congestion, and defer or reduce the scope of physical upgrades. Because feasible reconfiguration options are typically identified using EMS-quality node-breaker models and operational topology optimization tools, coordination between planning and operations is required to ensure that candidate configurations are implementable and consistent with real-time operating practices. This is akin to identifying Operating Guides which may be used in the planning horizon. In planning studies, TTO candidates are evaluated using security-constrained power flow, contingency analysis, and scenario-based assessments to ensure that proposed configurations maintain thermal, voltage, stability, and protection performance under a wide range of system conditions.

In operations, effective deployment of TTO requires tight integration with EMS and market and reliability decision-support tools, along with standardized procedures and communication protocols. Formal validation of reconfiguration actions, development of operational guidelines, and coordination with regional operators are essential to ensure that topology optimization actions can be executed safely and consistently in real time. These practices ensure that TTO is applied as a disciplined operational capability rather than as a manual or informal switching practice.

TTO is not intended to replace conventional transmission expansion. Rather, it serves as an operational GET that improves utilization of existing assets, provides near-term congestion mitigation, and increases operational flexibility while long-lead infrastructure projects are developed. When embedded within planning, operations, and governance processes, TTO provides a low-capital-intensity mechanism to enhance system performance, improve market efficiency, and support reliable operation of the transmission system.

10.2 Xcel Energy and Industry Experience

SPP and MISO have implemented TTO analysis and applied identified reconfigurations to resolve known congestion challenges. At SPP, TTO is implemented as part of reconfigurations for outage coordination and the lists of reconfigurations are published with the associated benefits for operator and planning use [19]. MISO has published results on implemented economic reconfigurations, where an estimated $113M in market-wide benefits was reported for 2025, alongside an additional $55.5M in estimated benefits year-to-date as of February 2026 [20]. While operating-case topology solutions identified by SPP and MISO can be valuable screening inputs, engineers should reassess those configurations under future-year planning assumptions because load patterns, generation dispatch, outages, and network topology may differ significantly from the operating conditions under which the optimization was performed.

For TTO, an appropriate application may be to use offline studies to identify and recommend potential topology adjustments, while allowing system operators to determine if and when those adjustments are warranted rather than implementing them automatically through real-time operating software. Topology changes may be particularly appropriate for outages or other special system conditions, while continuous topology adjustment to manage ongoing congestion may introduce additional operational risk.

Candidate topology adjustments should also be evaluated to ensure that they do not create adverse impacts following subsequent contingencies, including applicable higher-order contingencies such as TPL P2.3, P4, P5, and P7 events. Offline analysis can provide an appropriate framework for evaluating these conditions when the scope or computational requirements of real-time applications limit the extent of contingency analysis that can be performed.

If SPP and MISO publish the list of identified reconfigurations alongside their benefits, both SPS and NSP could implement those reconfigurations within planning models to evaluate the ability of the reconfiguration to act as either an alternative or near-term bridge to transmission projects. PSCo currently supports topology optimization through engineering studies and operating experience rather than through automated EMS-based tools. Implementing automated TTO would require software capable of evaluating contingency scenarios using system loading and generation cost data from the EMS or EMS-derived datasets.

11 | Planning Tools, Optimization, and Scenario-Based Evaluation

11.1 Research Implied Capabilities

Traditional transmission planning tools are necessary but not always sufficient to fully capture the value of GETs. Research shows advanced optimization-based methodologies enable systematic evaluation of device type, location, capacity, and control strategy. These research tools support mixed integer optimization combined with dc and ac power flow verification, allowing engineers to identify optimal combinations of GETs, non-wires alternatives, and conventional upgrades.

These methodologies are particularly valuable for evaluating interactions among multiple GETs. Greater benefits can often be achieved by pairing technologies, such as combining DLRs with APFC, TTO, and/or targeted physical upgrades. Scenario-based evaluation could allow Xcel Energy to assess performance across a range of operating conditions, resource mixes, and load growth trajectories.

This approach would enhance rigor, transparency, and consistency in GETs screening and ensure that investment decisions are supported by comprehensive technical analysis rather than isolated sensitivity studies.

11.2 Xcel Energy Experience and Challenges

While optimization-based methodologies have shown value in the National Labs and research environments, challenges remain for widespread implementation at the utility level. As a result, Xcel Energy is currently focused on systematically evaluating GETs for transmission projects that meet defined screening criteria (see Section 12), while continuing to explore opportunities to incorporate more advanced optimization-based approaches.

Consistent with this approach, Xcel Energy currently evaluates GETs on a case-by-case basis rather than relying on fully automated optimization frameworks. Several factors limit broader implementation of optimization-based methodologies, including:

- Data availability and quality
- Software and modeling limitations
- Study timelines
- Implementation complexity
- Limited operational experience and confidence in the technologies
- Control over system optimization sits with the regional operators (MISO, SPP)

To support the evaluation of GET alternatives, Xcel Energy is evaluating new software tools for pilot applications while also working with its existing vendors to incorporate GETs analysis into existing transmission planning tools and workflows.. Adoption of such tools will enable engineers to evaluate trade-offs between GETs and traditional solutions in steady-state reliability analyses and provide a more structured framework for screening alternatives.

12 | GETs Screening and Qualification Framework

To ensure consistent, transparent, and defensible evaluation of GETs, Xcel Energy will apply a standardized screening and qualification framework as part of the transmission planning alternatives analysis process. This framework is designed to systematically identify candidate applications for the four core GETs options and to ensure that GETs are considered in a disciplined manner alongside conventional transmission solutions. Table 4 summarizes the planning tools and representation for each GET.

TABLE 4. Mapping of GETs to Xcel Energy planning tools

GET OPTION	PRIMARY XCEL PLANNING TOOLS	MODELING REPRESENTATION
Advanced conductors	PSSE, PSLF, TARA, PROMOD	Updated thermal ratings, conductor electrical parameters, structural and clearance limits
Dynamic line ratings	PSSE, PSLF, TARA, PROMOD	Adjusted static/seasonal/monthly ratings, capped probabilistic limits, sensitivity cases
Advanced power flow control	PSSE, PSLF, TARA, PSCAD, PROMOD	Explicit controllable series elements, equivalent impedance or phase angle control
Transmission topology optimization	PSSE, PSLF, TARA, PROMOD	Breaker switching cases, alternate topology scenarios, contingency-based reconfiguration

While economic transmission analysis (i.e. nodal production cost modeling) is not required for all the GETs discussed in Table 5, it may support investment decisions by providing insight into how GETs can reduce overall system production costs, through reduction of curtailment and congestion. In other words, to the extent that GETs allow cheaper generation to operate for more hours, it will reduce the overall cost. Nodal production cost modeling is currently performed using PROMOD at Xcel Energy. For SPS facilities located within SPP, engineers should distinguish between internal planning assumptions and GET benefits that may be recognized in regional planning, transmission service, or interconnection studies. Planning credit should only be assigned where performance assumptions are consistent with applicable regional planning requirements

TABLE 5. Mapping of GETs to transmission study types

GET OPTION	REQUIRED STUDY TYPES	PRIMARY OBJECTIVES
Advanced conductors	Steady-state thermal, voltage, contingency analysis	Quantify structural ampacity increases and post-contingency performance
Dynamic line ratings	Probabilistic thermal analysis, sensitivity studies, risk-based planning studies	Quantify latent capacity and assess operational availability risk
Advanced power flow control	Steady-state power flow, contingency analysis, voltage studies	Redirect flows and mitigate congestion under normal and contingency conditions
Transmission topology optimization	Security-constrained power flow, contingency screening, economic analysis	Identify repeatable switching actions for congestion relief

The screening framework is applied during routine congestion reviews, reliability assessments, interconnection-driven studies, and long-term transmission planning cycles. It provides a structured mechanism to identify situations where GETs may provide material system benefits and to document the technical basis for advancing or excluding GETs as viable alternatives.

TABLE 6. Benefit–cost framework for GETs

GET OPTION	PRIMARY BENEFITS	PRIMARY COSTS AND RISKS
Advanced conductors	Structural ampacity increase; long-term capacity enhancement; corridor life extension; reduced need for new rights-of-way; improved post-contingency performance	Higher material costs; construction complexity; outage coordination; structural validation costs; long-term thermal aging considerations; terminal-equipment limitations; remaining life of supporting structures; installation-quality risk; vibration and galloping; and potential redistribution of power flows to other facilities due to changes in conductor impedance
Dynamic line ratings	Latent capacity utilization; congestion reduction; deferred capital upgrades; improved situational awareness; seasonal and weather-driven capacity gains	Sensor and communications costs; data quality and cybersecurity; operational uncertainty; availability risk; limiting span constraints; ongoing maintenance; confidence in ratings algorithm; difficulty accurately representing localized wind conditions along the full line; lack of industry performance and standard validation methodologies; and insufficient confidence in rating accuracy for reliability-dependent operation
Advanced power flow control	Targeted congestion relief; controllable power flow; interconnection enablement; asset life extension (PST wear reduction); modular scalability; fast deployment	Power electronic device costs; protection coordination; control interaction studies; maintenance of power electronics; EMS integration complexity; potential overloads on other facilities due to redirected flows; voltage, dynamic, and EMT interactions; substation-space limitations; communications and cybersecurity requirements; and limited operator confidence in autonomous control

GET OPTION	PRIMARY BENEFITS	PRIMARY COSTS AND RISKS
Transmission topology optimization	No-capital congestion relief; operational flexibility; deferral of upgrades; improved utilization of parallel paths; repeatable switching benefits	Increased operational complexity; training requirements; risk of misconfiguration; dependence on EMS decision support; limited applicability for some constraints; node-breaker to bus-branch model translation challenges; thermal, voltage, stability, and protection impacts from switching; operator authorization and regional coordination requirements; and the possibility that an operating-case reconfiguration may not remain effective in future planning conditions

12.1 System Need Identification

The initial screening process identifies system needs based on applicable NERC TPL performance requirements, regional and local planning criteria, interconnection study obligations, and economic planning assessments. The evaluation also considers transmission paths with persistently high congestion costs or recurring redispatch identified through production cost and reliability simulations, corridors constrained by clearance or right-of-way limitations, and conventional transmission solutions with significant permitting, siting, and construction lead times. Figure 9 provides a flowchart of evaluation steps based on system need identification, with details for the steps further explained in subsequent sections. The screening box that says "Does this issue appear in the 3+ year horizon?" is intended to consider whether the overload is showing up in near-term *and* long-term models. If it is only showing up in the near-term, GETs like DLR and TTO are preferred. However, if it shows up in models beyond 3 years, it should move through the full process to look at the tradeoffs between conventional solutions and long-term GETs like APFC and advanced conductors. Additional indicators include rapid load growth, high concentrations of inverter-based resources, and repeated operational switching actions used to manage flows. These conditions signal opportunities where enhanced asset utilization, controllability, or operational flexibility may provide near-term value. For a project to be economical, a benefit-to-cost (B/C) ratio of greater than one is required. This means that the expected benefits of the project exceed the costs. While reliability benefits can be hard to quantify in benefit calculations, recent industry guidance related to quantifying reliability benefits for Order 1920 may be helpful. Refer to Table 7 as a summary of the role of GETs across different planning horizons.

FIGURE 9. Decision framework for evaluating grid-enhancing technologies after an overload is identified

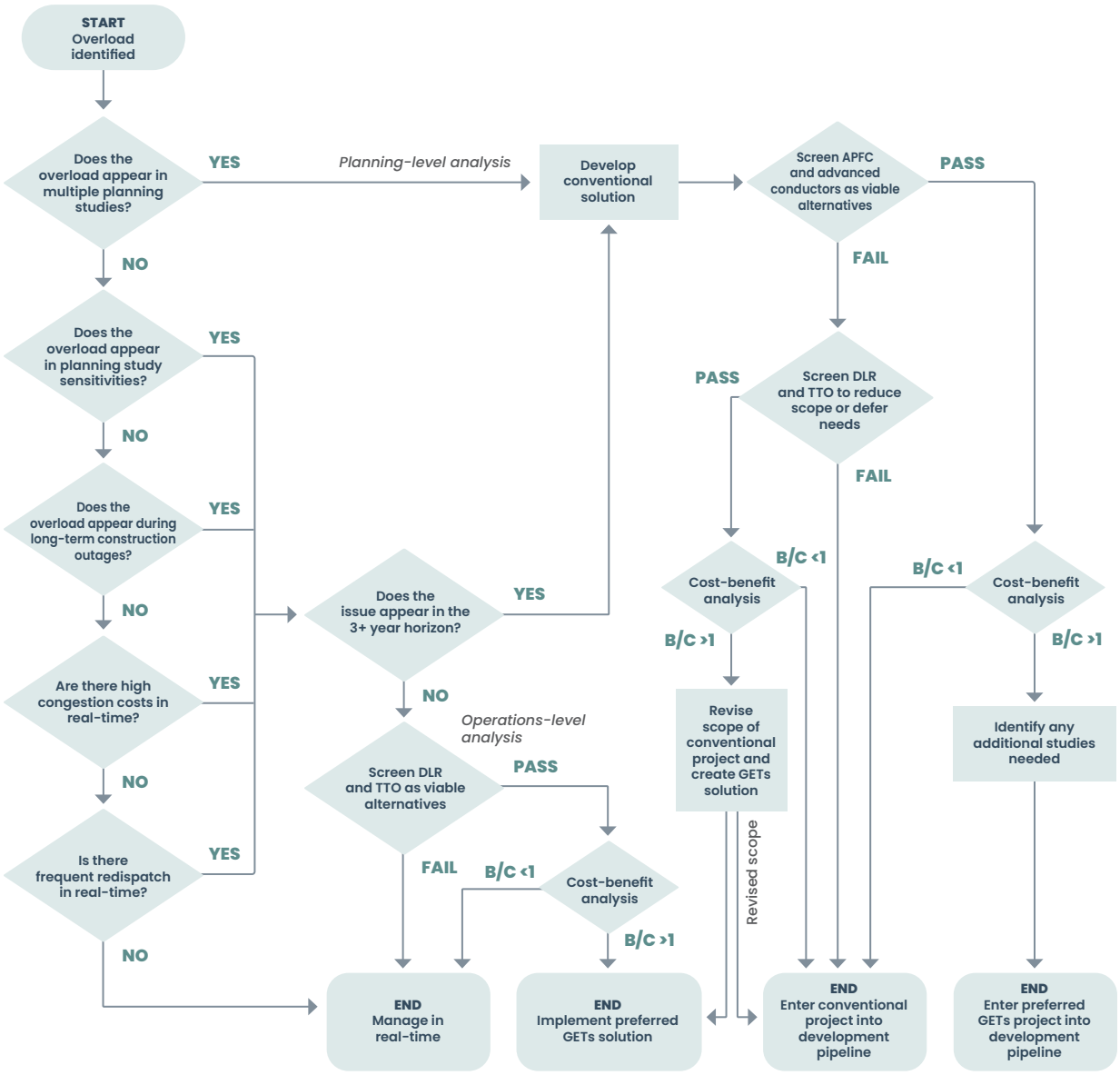


TABLE 7. Role of core GETs across Xcel Energy planning horizons

PLANNING HORIZON	PRIMARY GETS ROLE	REPRESENTATIVE APPLICATIONS
Near-Term (1–3 Years)	Interim congestion relief	DLR deployment, APFC, TTO for recurring overloads
Mid-Term (3–7 Years)	Deferral and scope reduction of upgrades	Advanced conductors, expanded APFC deployment, hybrid GETs solutions
Long-Term (7+ Years)	Complementary to major expansion	Combined GETs and new transmission to optimize corridor utilization

12.2 Line Ratings Relative to Structures and Limiting Equipment

Thermal ratings are limits beyond which the structural integrity of the equipment would be compromised and may not function through its expected lifespan. A transmission facility rating represents the maximum electrical loading that can be permitted while satisfying applicable thermal, mechanical, clearance, equipment, and operating limitations. For an overhead conductor, allowable current is determined through a heat-balance calculation that considers conductor temperature, ambient conditions, solar heating, wind, and conductor properties. The usable facility rating is ultimately governed by the most limiting series element or applicable operating constraint, which may be the conductor, a critical span, terminal equipment, protection-related equipment, or another component.

Advanced conductors and DLR are two methods to increase ratings on a line. To determine the appropriateness of these solutions, an initial screening should review the proposed line to be uprated within the context of its neighboring electrical equipment.

Line ratings are determined not only by the limits of the conductors but also by supporting equipment inside the substation, such as bus bars, current and voltage transformers used for protective relaying, wave traps, etc. If the limiting element is within the substation, improving the rating of the conductor through advanced conductors or DLR will not improve the overall rating of the line unless the required substation upgrades are completed.

Because current flow within the power system is based on the physics of the system, changing line parameters like impedance (a consequence of switching to advanced conductors, though not of using DLR) can shift flow within the system. If the upgraded path is part of a link of several parallel paths, replacement might pull additional flow onto the path, causing overloads on non-upgraded segments. It is also possible that replacement with an advanced conductor may shift flows to other parts of the system where there isn't enough headroom. For this reason, detailed analysis is required to ensure advanced conductor replacement does not create the need to upgrade other parts of the system.

12.3 Advanced Conductors Screening

Advanced conductors are evaluated where structural and clearance constraints limit traditional reconductoring options. Screening focuses on assessing whether existing structures can accommodate the increased sag and loading associated with higher conductor operating temperatures and whether meaningful ampacity increases can be achieved without widespread structure replacement. Screening may also include consideration of project-specific electromagnetic field (EMF) and audible-noise analysis based on changes in current loading, conductor characteristics, geometry, or clearances. Corridors with high utilization, constrained rights-of-way, and limited routing alternatives are prioritized. Construction outage feasibility, compatibility with long-term corridor development plans, and asset lifecycle

considerations are incorporated to ensure alignment with both near-term reliability and long-term infrastructure strategy. Screening should compare the incremental ampacity and lifecycle value of advanced conductors with the utility's standard conductor solution, rather than evaluating advanced conductors only against complete line reconstruction or greenfield expansion. For projects developed through a competitive RTO process, the screening record should also distinguish the technically preferred lifecycle solution from the configuration selected to meet RFP requirements and competitive cost objectives, including whether a later advanced-conductor upgrade would require additional outages, structural work, or replacement of recently installed conductor.

12.4 Dynamic Line Ratings Screening

DLRs are evaluated where ambient conditions exhibit significant seasonal or diurnal variability and where weather patterns are conducive to increased thermal capacity. Screening emphasizes identification of corridors where historical congestion coincides with favorable ambient conditions and where limiting spans and clearance constraints can be effectively monitored. Communications and sensor infrastructure availability is assessed, along with the ability to define capped planning ratings consistent with Xcel Energy's operational risk tolerance. These factors ensure that DLR deployments provide reliable, actionable capacity increases while maintaining operational confidence.

12.5 Advanced Power Flow Control Screening

APFC is screened in areas where congestion is driven by parallel path utilization and where power flows are sensitive to modest impedance or phase angle changes. Particular attention is given to interconnection-driven deliverability constraints and to corridors where existing phase-shifting transformers experience high tap change frequency or operational wear. Screening evaluates siting feasibility, compatibility with protection schemes, and alignment with system operating practices. This ensures that APFC deployments provide controllable, durable congestion relief without introducing adverse system interactions.

12.6 Transmission Topology Optimization Screening

TTO is evaluated where known repeatable switching actions reduce overloads or where congestion patterns are sensitive to breaker configuration. Screening assesses the operational feasibility of alternate topologies under contingency conditions, availability of EMS decision support and switching authorization tools, and the ability to validate switching strategies through planning studies. Operational complexity, training requirements, and procedural impacts are evaluated to ensure that topology optimization strategies are sustainable and aligned with reliability and operational discipline.

12.7 Exclusion, Escalation, and Documentation

GETs applications are excluded or replaced with conventional transmission solutions when technical studies indicate unacceptable dynamic, protection, or operational risks, insufficient confidence in operational availability, or inability to integrate with EMS and established procedures. Applications may also be excluded when benefits are insufficient relative to implementation and lifecycle costs. All screening outcomes, including advancement or exclusion decisions, are documented as part of the formal alternatives analysis record to support transparency, governance, and regulatory defensibility.

Through this structured screening and qualification framework, Xcel Energy ensures that GETs are evaluated consistently, aligned with system needs, and integrated into core planning and decision-making processes as complementary tools to conventional transmission expansion.

12.8 Technology Selection Considerations

The preceding screening criteria provide a structured framework for evaluating potential GETs applications. While technology selection remains dependent on project-specific conditions and engineering judgment, several general considerations have emerged from industry experience and Xcel Energy evaluations that can help guide the selection of appropriate solutions.

Planning studies first identify overloads or required rating increases. From there, if the overloads requiring mitigation are in the operational timescale, the preferred options are different from overloads with a longer time frame.

- **In the operational timescale (near-term, physically constrained corridors):** In highly constrained environments (e.g., dense urban corridors where rebuild or reconductoring is not feasible), and where additional capacity is needed for a limited number of hours per year, DLR should be considered after validating results using detailed models (e.g., if node-breaker representation is such that TTO is not applicable). Studies should be rerun with updated ratings to ensure congestion is not simply shifted elsewhere.
- **Otherwise:** Advanced conductors are generally the preferred solution. If advanced conductors do not provide sufficient headroom, then a rebuild or greenfield expansion should be considered.

DLR is particularly useful in the following scenarios and may be preferred over advanced conductors in these situations:

- Corridors that are already fully built out, where reconductoring or structural upgrades are not feasible
- Situations where additional capacity is needed only for a limited number of hours per year (e.g., less than 200 hours annually) and those hours align with hours where DLR is reasonably expected to provide higher ratings.

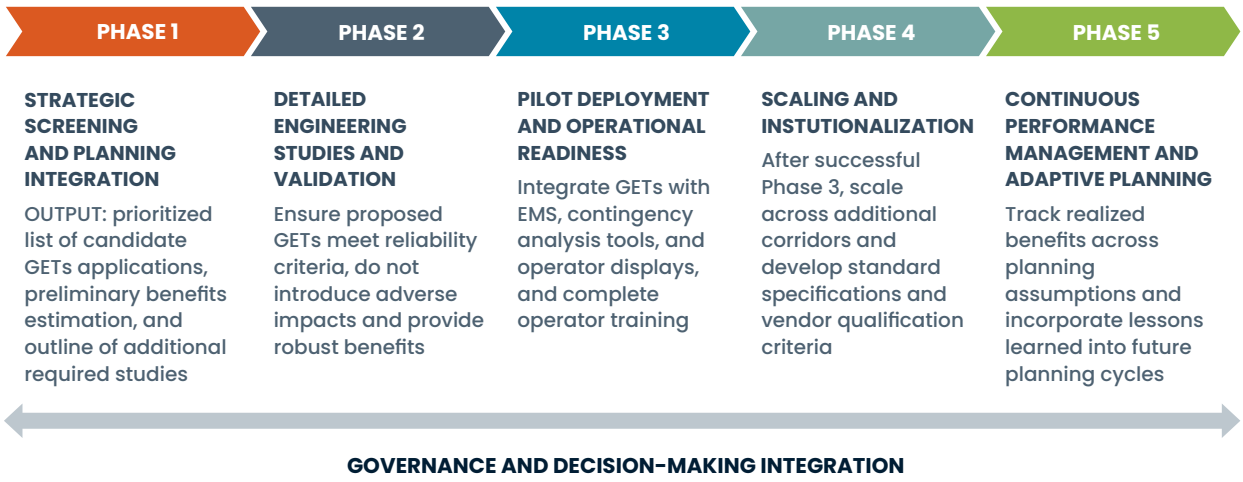
- Time-sensitive interconnection needs, such as accommodating large load additions (e.g., data centers) requiring near-term solutions.

In these cases, DLR may provide incremental capacity without the need for major physical modifications, whereas advanced conductors require structural and/or reconductoring work.

13 | Formal Implementation Roadmap for GETs Deployment

To ensure that GETs are deployed in a disciplined, scalable, and institutionally sustainable manner, Xcel Energy is proposing to implement GETs through a phased roadmap aligned with existing planning, operations, and capital governance processes. This roadmap establishes a structured pathway from screening and evaluation through operationalization and long-term institutionalization, ensuring that GETs are integrated as standard planning and operational tools rather than treated as isolated pilot initiatives. An overview of the roadmap is shown in Figure 10, with additional details in the following sections. The decision gate framework ensures that GETs are evaluated rigorously, aligned with reliability standards, and integrated within capital planning and operational approval processes. This structured decision gate process ensures that GETs are advanced only when they meet defined technical, operational, economic, lifecycle cost-benefit, and governance criteria, and that conventional transmission solutions are pursued when GETs are not appropriate or sufficient.

FIGURE 10. Xcel Energy roadmap to GETs deployment



13.1 **Phase 1:** Strategic Screening and Planning Integration

The first phase focuses on the systematic identification of candidate corridors, substations, and interfaces where GETs may provide material system benefits. During this phase, GETs are incorporated into the transmission planning alternatives analysis process as complementary options alongside conventional upgrades, consistent with evolving regulatory constructs.

Screening criteria applied in this phase include recurring thermal overloads, persistent congestion costs, clearance-limited corridors, long lead-time conventional expansion projects, and areas with high penetration of inverter-based resources. Steady-state planning tools are used to identify constraints that may be suitable for GETs application. For DLR, historical weather data and ambient conditions are analyzed to estimate probabilistic availability and define capped planning ratings to ensure reliability under varying conditions. For advanced conductors, structural and clearance constraints are evaluated to determine technical feasibility and the magnitude of potential ampacity increases. For advanced conductors and DLR, the delta between line ratings and substation equipment determines potential headroom, and this screening may include consideration of simple endpoint upgrades when relevant. For APFC and topology optimization solutions, sensitivity analyses are conducted to assess controllability, flow redistribution, and achievable congestion relief.

Once it is determined a GET is appropriate for a particular thermal overload, forward-looking transmission production cost modeling should be completed to validate the solution over all hours of the year. This analysis should also include an evaluation of the APC, which indicates the economic benefit of the GET, alongside an evaluation of curtailment levels (if need is driven by high concentrations of inverter-based resources).

The outputs of this phase include a prioritized list of candidate GETs applications, preliminary benefit estimates, and identification of additional study requirements for subsequent phases, including more detailed steady-state, dynamic, and, where applicable, EMT analyses. These outputs are integrated into Xcel Energy's internal transmission planning documentation and alternatives analysis processes to ensure alignment with long-term system development strategies and regulatory expectations.

13.2 **Phase 2:** Detailed Engineering Studies, Validation, and Lifecycle Cost Benefit Analysis

The second phase focuses on detailed technical validation of shortlisted GETs applications. This phase includes full ac power flow studies, contingency analyses, voltage performance evaluation, and, where appropriate, dynamic and EMT-level studies. The objective is to validate that proposed GETs deployments meet reliability criteria, do not introduce adverse interactions, and provide robust benefits across a range of operating conditions.

For DLR, this phase includes refinement of probabilistic models, identification of limiting spans, evaluation of clearance constraints, and assessment of substation bottlenecks. For advanced

conductors, detailed structural and thermal analyses are conducted to confirm feasible operating limits and construction requirements. Where appropriate, project-specific evaluation may also include consideration of EMF and audible noise based on conductor characteristics, current loading, geometry, and clearances. For APFC devices, control interactions, protection coordination, and voltage impacts are evaluated. For topology optimization, repeatable switching actions are validated under a wide range of contingencies and operating scenarios.

This phase also includes development of conceptual designs, cost estimates, construction scopes, and implementation timelines. The results support formal benefit-cost analysis and provide the technical basis for investment decisions. Cost-benefit analysis should consider full lifecycle costs of the GET and when possible compare to the costs of a conventional solution over the same lifespan. Some benefits which may be relevant include: reduced expected maintenance costs, reduced energy costs from lower line losses, or lower system energy costs from allowing a low-cost generator to interconnect sooner.

13.3 **Phase 3:** Pilot Deployment and Operational Readiness

The third phase focuses on limited-scope pilot deployments to validate field performance, operational integration, and data quality under real-world conditions. Pilot projects are selected to represent high-value use cases and to exercise key operational workflows.

During this phase, the required operational architecture is defined and validated, including evaluation of EMS integration, contingency analysis tools, operator displays, and cybersecurity requirements. Where pilot projects are intended for operational use, compatibility with EMS systems and applicable Critical Infrastructure Protection (CIP) program requirements must be verified. In some cases, pilot deployments may initially operate outside the EMS environment and be used for operational awareness only while technology performance and operational readiness are assessed. Operational procedures, fallback strategies, and abnormal condition responses are developed and tested. Operator training is conducted to ensure that system operators understand how to interpret and use GETs outputs in real-time decision-making.

Performance metrics are established to track realized benefits, including congestion relief, thermal utilization, reliability impacts, and operational complexity. Pilot results are documented and reviewed to inform scaling decisions and procedural refinements.

13.4 **Phase 4:** Scaling and Institutionalization

Following successful pilot validation, GETs are scaled across additional corridors and applications where similar benefits are expected. During this phase, GETs are formally incorporated into standard transmission planning templates, alternatives analysis guidelines, and capital project development processes.

Standard specifications, vendor qualification criteria, and engineering standards are developed to streamline future deployments. GETs assumptions, modeling practices, and operational procedures are codified to ensure consistency across planning regions and operating centers. This phase ensures that GETs are no longer treated as special projects, but rather as standard tools within Xcel Energy's transmission planning and operations toolkit. Xcel Energy's adoption of advanced conductors is the first GET that has achieved Phase 4 in the implementation roadmap.

13.5 **Phase 5:** Continuous Performance Management and Adaptive Planning

The final phase establishes ongoing performance management and continuous improvement. Realized benefits are tracked against planning assumptions, and discrepancies are analyzed to refine modeling methodologies and screening criteria. Asset performance, maintenance requirements, sensor reliability, and data quality are monitored to ensure long-term sustainability.

Lessons learned are incorporated into future planning cycles, allowing GETs deployment strategies to evolve as system conditions, technology capabilities, and regulatory expectations change. This adaptive approach ensures that GETs remain aligned with Xcel Energy's long-term transmission strategy and reliability objectives.

13.6 Governance and Decision-Making Integration

Throughout all phases, GETs deployment is proposed to be governed through Xcel Energy's existing capital planning, project approval, and reliability oversight processes. Investment decisions are supported by documented technical studies, benefit-cost analysis, and risk assessments consistent with traditional transmission projects. This ensures transparency, accountability, and alignment with regulatory expectations.

By embedding GETs within established governance structures, Xcel Energy ensures that these technologies are deployed strategically, evaluated rigorously, and sustained over the long term as part of a comprehensive transmission planning and operations framework.

14 | Operational Integration and Lifecycle Management

To realize full value, GETs must be fully integrated into real-time operations and asset management processes. This includes integration into EMS, contingency analysis tools, and operator displays. Operators must have visibility into real-time ratings, device setpoints, and

topology configurations, along with clear procedures for fallback operation and abnormal conditions.

Lifecycle considerations are central to sustainable GETs deployment. Field experience highlights the importance of addressing sensor accuracy, environmental exposure, cybersecurity, communication reliability, maintenance requirements, and long-term performance degradation. Specification development, validation testing, redundancy planning, and performance monitoring are incorporated to ensure dependable long-term operation.

Training, documentation, and institutional knowledge development are also critical. As GETs become part of standard operations, operator training and engineering procedures must evolve to reflect new tools, new sources of uncertainty, and new decision-making processes.

15 | Strategic Role of GETs in Xcel Energy's Capital Planning

GETs will be incorporated into Xcel Energy's capital planning and governance framework as complementary technologies that enhance asset utilization and operational flexibility. They will be evaluated alongside conventional upgrades in alternatives analysis, with costs, benefits, and risks documented in a manner consistent with traditional transmission investments.

Performance tracking and post-implementation evaluation will be used to quantify realized benefits, including congestion relief, deferred capital spending, improved reliability, and asset life extension. These results inform future planning cycles and support continuous improvement in GETs screening, deployment, and operational integration.

16 | GETs Escalation-to-Transmission Criteria

Xcel Energy will escalate from GETs-based solutions to conventional transmission expansion when defined technical, operational, or strategic thresholds are reached. This escalation framework ensures that GETs are used appropriately as complementary tools and that long-term infrastructure needs are addressed through traditional transmission investments when required. The existence of additional thermal capability should not be assumed to satisfy deliverability requirements unless supporting studies demonstrate transfer capability improvements under applicable planning conditions.

Escalation to conventional transmission solutions is triggered when studies indicate that GETs

cannot reliably or sustainably resolve identified system needs. This includes situations where projected load growth, resource interconnection, or transfer requirements exceed the feasible capacity increases achievable through GETs. In such cases, GETs may provide interim relief but are not considered sufficient as standalone long-term solutions.

Escalation is also required when GETs introduce unacceptable operational risk, including insufficient availability of DLR under stressed conditions, adverse dynamic or protection interactions associated with APFC devices, or operational infeasibility of topology optimization strategies under contingency conditions. If reliability performance depends on aggressive operational assumptions or manual intervention beyond established practices, conventional transmission solutions are advanced.

Long-term planning considerations also drive escalation. When congestion is structural in nature and persists across a wide range of operating conditions, or when corridors are projected to require sustained capacity increases over multiple planning horizons, conventional transmission expansion is pursued to ensure durable system performance. In these cases, GETs may be used as interim measures but do not replace the need for new facilities or major rebuilds.

Finally, escalation occurs when benefit-cost analysis demonstrates that lifecycle costs, operational complexity, or risk exposure associated with GETs exceed the costs and long-term benefits of conventional transmission investments. This ensures that capital allocation decisions are based on total system value rather than near-term deferral alone.

Through this escalation framework, Xcel Energy maintains a clear boundary between interim, complementary GETs applications and the long-term transmission investments required to meet enduring system needs.

16.1 Regulatory Alignment with Transmission Planning and Line Rating Requirements

Xcel Energy's GETs integration framework is aligned with evolving federal transmission planning and line rating requirements, including regulatory expectations related to enhanced transmission utilization, long-term regional planning, and transparency in alternatives analysis.

The integration of DLR directly supports regulatory requirements to utilize ambient-adjusted and dynamic ratings where appropriate to reflect actual operating conditions. By incorporating capped and probabilistic DLR into planning studies, Xcel Energy will ensure that transmission capacity assumptions more accurately reflect physical conditions while maintaining defined reliability margins and operational fallback limits. This approach supports improved asset utilization while preserving operational confidence and compliance with reliability standards.

The structured consideration of GETs within long-term and regional transmission planning processes aligns with regulatory expectations for comprehensive evaluation of alternatives to

meet future system needs. By explicitly screening, validating, and documenting GETs as part of the alternatives analysis process, Xcel Energy will ensure that both conventional transmission and nontraditional solutions are evaluated in a transparent, consistent, and technically rigorous manner.

The formal decision gate, screening framework, and escalation criteria further support regulatory objectives by demonstrating that GETs are integrated into governance processes and that long-term transmission needs will continue to be met through conventional infrastructure where required. This alignment ensures that GETs are deployed to enhance near-term flexibility and asset utilization without undermining long-term transmission development necessary to support reliability, resource integration, and load growth.

Through this framework, Xcel Energy demonstrates a balanced and compliant approach that leverages GETs to improve system performance while maintaining a robust and forward-looking transmission expansion strategy.

17 | Conclusion

GETs represent an important part of Xcel Energy's transmission planning and operations strategy. While GETs will not replace the need for new transmission lines and major infrastructure investments, they provide valuable near- to medium-term capabilities that unlock latent capacity, improve asset utilization, enhance operational flexibility, and support system reliability. GETs will be evaluated as complementary tools that improve utilization and operational flexibility while recognizing that transmission deliverability requirements and NERC reliability obligations must be maintained.

By integrating GETs into established planning processes, aligning them with steady state, production cost, dynamic, and EMT studies, and fully incorporating them into operational systems and governance structures, Xcel Energy can leverage GETs to manage near-term system needs while continuing to develop the long-term transmission infrastructure required to support future growth and reliability.

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