Assessment and Evaluation of Grid Enhancing Technologies (GETs)

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1 Introduction

US electricity demand is projected to grow nearly 16% by 2029 [1], putting new urgency behind the need for grid upgrades and the addition of new generation resources. The surge in renewable energy projects aiming to connect to the grid has highlighted longstanding transmission capacity challenges. The U.S. Department of Energy (DOE) found that to achieve a 100% clean energy grid by 2050 under a high electricity demand scenario, total U.S. transmission capacity must expand 2.7–4.1 times the 2020 level [2]. Yet, at the end of 2023, nearly 2,600 GW of renewable energy projects were stuck in queues due to high network upgrade costs and insufficient transmission capacity [3]. These bottlenecks resulted in over $11.5 billion in congestion charges for U.S. consumers in 2023 [4].

Traditional grid planning and operations, rooted in traditional practices, can struggle to adapt quickly to modern demands. Transmission owners (TOs) and grid operators typically prioritize conventional investments such as traditional line reconductoring, rebuilding, or construction of new lines. Even when system expansion is needed, these processes are slow and costly, hampering swift implementation of essential upgrades. A modernized approach to grid planning and operation is critical in order to safely, reliably, and affordably meet the electricity demands of the future.

Grid planning should prioritize flexibility, speed, and the dynamic capabilities of modern technologies when planning investments and evaluating solutions. Grid Enhancing Technologies (GETs) can play a critical role in grid modernization by optimizing the efficiency of existing infrastructure and unlocking unused capacity [5].

GETs include hardware and software solutions that allow transmission owners and operators to rapidly and cost-effectively increase transmission capacity on both new and existing lines, all while ensuring grid reliability, safety, and efficiency. The term "utility" is used throughout this playbook to refer specifically to transmission owners (TOs). As discussed further, the Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) which operate the transmission system, also play an important role in GETs implementation.

By introducing flexibility and generating data insights, GETs enhance grid reliability through real-time monitoring of grid conditions and enable grid optimization. GETs not only mitigate congestion and reduce upgrade costs but also accelerate the integration of renewable energy, ensuring the grid remains resilient and adaptive in the face of evolving demands [6].

This report will outline three commercially available GETs and discuss their potential for integration in grid planning and operations, enabling both the system and its customers to reap the benefits of early adoption and enhanced functionality as the grid evolves to become more data-driven and digitally enabled. The focus is on Dynamic Line Ratings (DLR), Advanced Power Flow Control (APFC) and Transmission Topology Optimization (TTO) software, emphasizing their data-driven and dynamic capabilities. The subsequent sections will also explore pathways for technology deployment and necessary technical adaptations.

2 Understanding Power System Technologies

DLR, APFC, and TTO are crucial facilitators for the energy transition and managing substantial electricity demand growth. These technologies enhance the grid's capacity, reliability, and efficiency, allowing for a smoother transition to renewable energy sources.

Dynamic Line Rating (DLR) systems continuously calculate the thermal carrying capacity of transmission lines using real-time and forecasted environmental conditions and/or line behavior. Different DLR technologies can utilize various line monitoring and measurement techniques, including line-mounted sensors, tower-mounted sensors, fiber optic cables, tension/sag monitoring, and weather station data. Data from these sensors and forecasts are used in computational modeling to determine the thermal carrying capacity of the transmission line that can then be used in the planning and operational environments. TOs and ISOs/RTOs traditionally employ various types of ratings, which can be categorized into different "stages" from least to most dynamic.

For non-technical overview of DLR and examples, see Unlocking Power Line by Line.

Figure 1. Types of Line Ratings

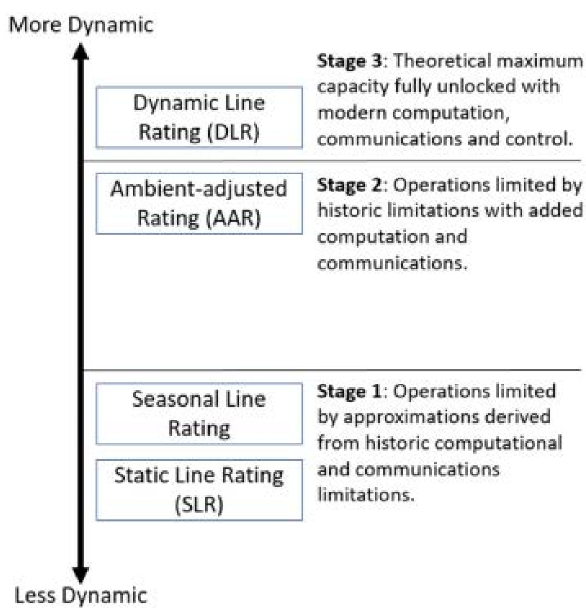


Figure 1 illustrates the different types of line ratings and their respective “stages.” DLR measures conditions on transmission lines to provide real-time and forecasted insights into line capacity and enabling tailored rating profiles [7].

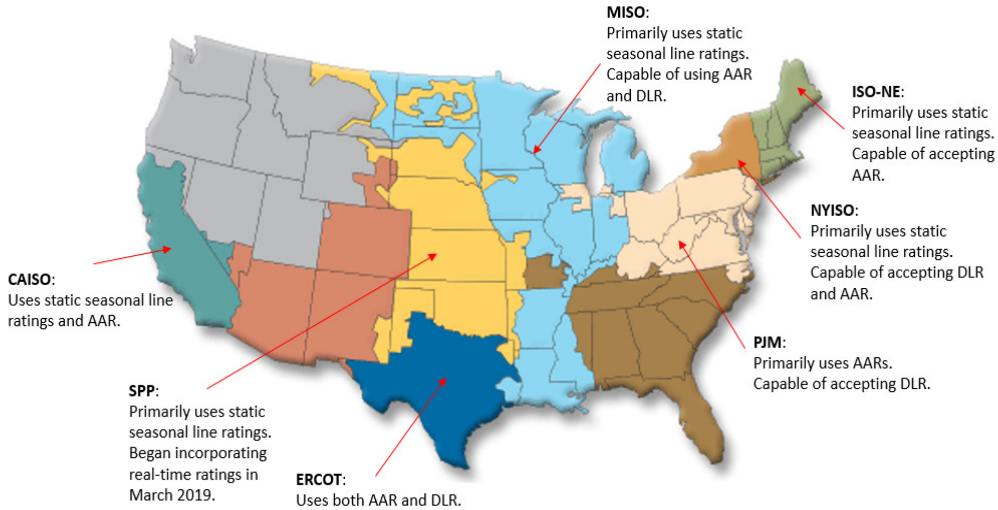
Stage 1 includes Static Line Rating (SLR) and Seasonal Line Rating. SLR calculates thermal ratings based on the most conservative assumptions about the transmission line’s operating environment. Seasonal ratings, on the other hand, are the most commonly used line ratings, and consist of static ratings set for two six-month periods each year. These two sets of static ratings are each based on worst-case expected conditions, such as high ambient temperatures, low wind speeds, and high solar radiation during that six-month period of time.

Stage 2 includes Ambient-Adjusted Ratings (AARs), which utilize ambient air temperature data to adjust ratings at least hourly. FERC Order No. 881 required transmission providers to implement AARs and required ISOs/RTOs to allow the use of DLR. Finally, Stage 3 contains DLR, the most variable and adaptable of all rating methods. DLR provides actual measurements of transmission line parameters to offer real-time visibility into line capacity and provides customized rating profiles for otherwise identical lines.

DLR provides significant benefits, particularly in areas with high winds, as the cooling effect of the wind has the greatest impact on the current-carrying capacity of conductors. Likewise, in colder temperatures, lines can also carry more current, which is advantageous for utilities facing transmission constraints during winter peaks. Beyond these specific situations, DLR generally identifies additional transmission capacity beyond ambient adjusted ratings and static ratings. Even when DLR does not physically increase capacity, it offers insights for operating assets based on their true capacity, while maintaining safety and reliability.

DLR can be incorporated into the control systems of both individual TOs and ISOs/RTOs, enabling full utilization of grid capacity. The integration of DLR data into system operations can empower operators to make decisions that will reduce generator curtailment, lower congestion costs, improve system reliability and safety, and increase the number of opportunities for faster, more economical, and cleaner generation to meet both existing and growing demand. Additionally, DLR data improves operational intelligence and situational awareness, which can be useful for effective line maintenance and vegetation management. DLR can also be used to help identify bottlenecks on transmission systems, helping to guide more efficient capital investment.

Figure 2. ISO/RTO Line Rating Adoption



Across the United States, the adoption of line rating technologies varies significantly among different ISOs and RTOs, as illustrated in Figure 2. FERC Order 881 requires all FERC-regulated ISOs and RTOs, except NYISO which has a 3-year delay, to be capable of accepting DLR by summer of 2025. Most regions employ ratings that are more advanced than SLR but less sophisticated than DLR, such as seasonal line ratings and AARs. Many regions are beginning to adopt DLR, allowing for the expansion of thermally limited flowgates and reduced customer costs. Compared to the costs of traditional transmission expansion projects, the costs of implementing DLR are modest. However, getting the most out of DLR may require upfront capital investments [8], including but not limited to the cost of: equipment/infrastructure, installation, integration into Energy Management System software, operator and operations planning training, and Market Integration (e.g., consider a Market that runs on fixed condition assumptions in the Day-Ahead Market with a Real-Time Market dispatch informed by DLR; systematic differences may be created that virtual traders can profit from).

Key Benefits of DLR	Description
Operational Use	▪ Provides real-time insights into the thermal carrying capacity of transmission lines allowing operators to fully utilize the grid without compromising safety or reliability. ▪ Minimizes curtailments and alleviates congestion, providing cost savings for utilities and consumers, due to the added visibility of line capacities. ▪ Improves situational awareness, aiding in line maintenance, vegetation management and asset monitoring.

Key Benefits of DLR	Description
Planning Horizon	■ Provides visibility into capacity constraints allowing more precise planning and staging for upgrades and investments. ■ Allows planners to evaluate different environmental scenarios improving resilience against variable conditions such as seasonal demand peaks. ■ Enables increases in capacity while larger upgrades are planned and constructed.

Advanced Power Flow Control (APFC) are advanced devices used for voltage regulation and power flow control. APFC is a type of Modular Static Synchronous Series Compensator (M-SSSC) that is a new advancement within the flexible alternating current transmission systems (FACTS) technologies, which leverage power electronics to alter line impedance, phase angle, and voltage magnitude in transmission systems. Traditional FACTS devices, such as static synchronous compensators (STATCOMs) and static var compensators (SVCs), have been utilized in transmission systems for many years. APFC enhances these traditional devices by incorporating modular digital power flow control technology, allowing for rapid and precise control of power flow.

For non-technical overview of APFC and examples of applications of Advanced Power Flow Control, see Unlocking Power by Redistributing Energy.

For the past decade, global electric grids have utilized modular power flow control technologies. These systems employ APFC components assembled into standardized, modular devices that offer adaptable solutions while maintaining the functionality and benefits of traditional power flow control technology, at the same time minimizing challenges.

APFC solutions function as Fixed Series Capacitors (FSCs) or series reactors by injecting a leading or lagging voltage in quadrature with the line current. Being active devices, APFCs can mitigate technical issues such as Subsynchronous Oscillation (SSO) and constant reactive power usage, which are common in passive devices and legacy compensation systems [9].

Through voltage injection using voltage-source converters, APFCs can effectively enhance or reduce the reactance of a specific circuit, enabling real-time control of power flow. This method is particularly effective in meshed electric grids for addressing loading violations by utilizing spare system capacity on alternative power pathways. APFCs operate at line potential without connecting to the ground and do not require an insertion/coupling transformer, unlike conventional SSSC solutions.

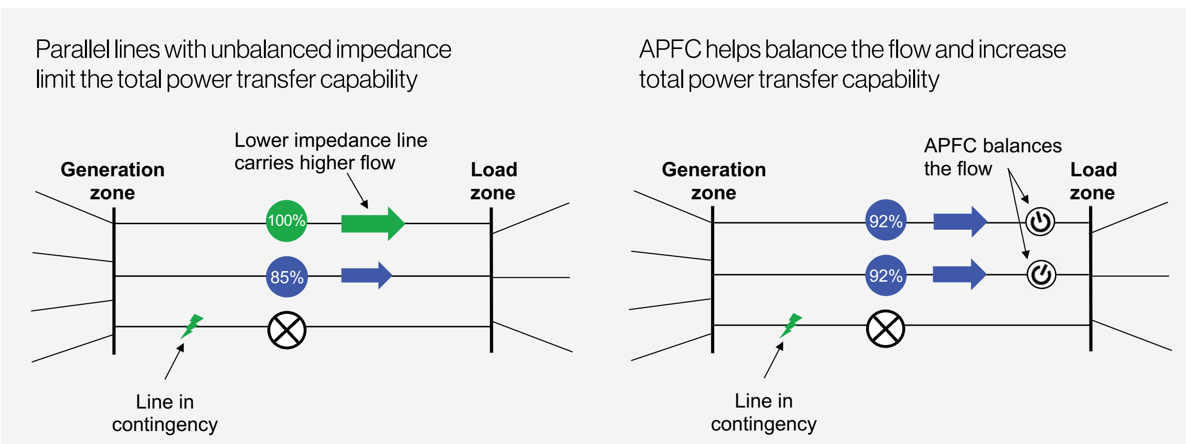
The modularity of APFC installations allows utilities to quickly and accurately respond to system demands and easily accommodate future needs by adding new modules. These devices are voltage-agnostic and can be redeployed to different lines with varying voltage levels. The rapid response time of the power electronics in APFCs allows operators to regularly adjust operational settings, enabling active management of power flows without compromising the devices' longevity. APFCs can operate in various control modes, adjusting the injected voltage based on the line current to maintain fixed reactance or keep the line current within operating limits [10].

Traditional FACTS like SSSC or FSC require significant civil construction, a large footprint, and unique designs tailored to specific applications and deployment sites. In contrast, the modular architecture of APFCs enables quick and cost-effective deployment and re-deployment with minimal specific design work, allowing the solution size to be scaled according to the changing needs of the transmission grid. APFC devices, available in modules ranging from 1 MVAr to 10 MVAr, are typically deployed as a fleet interconnected across all three phases, providing a continuous range of control up to the deployment's total rating. Utilities often deploy APFC devices in or near substations or as part of a mobile unit for rapid deployment. Key features and functionalities are provided below. The benefits of APFC are visualized in Figure 3 [11].

Key Features	Functionality
Voltage Injection	Injects a leading or lagging voltage in quadrature with the line current to enhance or reduce line reactance, enabling real-time power flow control.
Modularity	Modular and can be installed incrementally, allowing for future expansions and redeployments to different voltage levels.
Operational Flexibility	Power electronics allow for frequent adjustments to maintain optimal power flows without significant maintenance costs.
Reduced Footprint	Installations require significantly less space and civil construction compared to FSCs.

Key Benefits of APFC	Description
Operational Use	▪ Addresses contingency events (e.g., sudden loss of critical generation or transmission facilities) and redistributes power flows to alternate paths, relieving grid stress. ▪ Optimizes power flow distribution and improves power transfer capability by reducing loop flow. ▪ Enhances post-contingency damping performance, crucial for system stability.
Planning Horizon	▪ Facilitates greater integration of renewables without extensive and costly transmission upgrades and enables more granular control over power flows. ▪ Allows planners to explore and evaluate a wider variety of grid expansion and reinforcement options and ensures targeted, optimized investments aligned with future grid evolution and policy trajectories. ▪ Enables planning processes to accurately reflect the dynamic control capabilities of APFC technology which results in a robust, adaptable, and sustainable grid [12].

Figure 3. APFC Control Diagram



For non-technical overview of Transmission Topology Optimization and examples, see Unlock Power by Reshaping the Grid.

Transmission Topology Optimization Software reconfigures the grid's layout to optimize power flow, reducing congestion and enhancing the grid's resilience using existing hardware. Topology optimization uses complex algorithms to analyze the state of the grid and simulate various configurations to find the optimal one. This approach involves strategically reconfiguring the power grid by changing the status of circuit breakers, switches, or other controllable devices. This process includes switching transmission lines in or out, splitting bus sections, and switching substation breakers.

For instance, consider the case of parallel Extra-High Voltage (EHV), operating at 345 kV to 765 kV, and High Voltage (HV), operating at 100 kV to 230 kV, transmission lines, where a flowgate is limited by an HV transmission line for the loss of one of the EHV lines. By opening the HV line, transfer capability across the flowgate could potentially be expanded. Also, as the power system evolves and flows patterns change, topology optimization software can help identify reconfiguration options to optimize system performance for situations previously not encountered or extensively studied. For example, with the increase of offshore wind on the Atlantic coast, power flows into urban centers on the coast now being provided by the offshore wind may be significantly reduced or even reversed. The transmission supplying these urban centers was initially designed to serve load, now could support maximizing transfer capability across a region or portion of the system. On the distribution system, when a feeder is under stress due to rapidly increasing load, grid operators can transfer part or all of this load to adjacent feeders through substation switching actions, thus minimizing the risk of equipment failure and outages. Topology optimization solutions can be implemented swiftly to address unexpected events such as equipment failures or sudden changes in demand [13].

Key Benefits of Topology Optimization	Description
Operational Use	▪ Minimizes congestion and provides a balanced power distribution during system events, such as loss of transmission lines, transformers, etc., enhancing the overall operational efficiency of the grid. ▪ Prevents equipment failures and extends the lifespan of critical infrastructure through load redistribution.

Key Benefits of Topology Optimization	Description
Planning Horizon	▪ Identifies options for reconfiguration to maintain efficiency under scenarios not extensively studied previously. ▪ Provides pre-studied reconfiguration solutions that allow operators to address contingencies such as equipment failures, generation or demand surges in a timelier fashion. ▪ Identifies optimal grid conditions that improve grid efficiency and resiliency. ▪ Allows for future flexibility for reconfigurations through substation design decisions.

Additional background information on these technologies, their benefits and policies to support their use are provided in the WATT Coalition Playbook on Grid Enhancing Technologies.

3 Stages of Analysis

GETs should be considered in many stages of transmission planning and operations by integrating these technologies into modeling and decision-making. The main stages involved in the grid planning process include the following:

a. **Load Forecasting:** Predicting future power demand based on historical data, economic indicators, weather patterns, and other drivers is essential for generation and transmission planning. Accurate load forecasting helps in identifying the necessary capacity and resources to meet future demands efficiently. Utilities leverage a variety of tools to support load forecasting, including probabilistic models that identify various futures in the planning timeframe based on a set of variables (e.g. economic growth and electrification of sectors), to short-term models informed by expected weather conditions, DER profiles and similar day experience. GETs can also support this forecasting process. For example, detailed real-time data from DLR systems can be fed into forecasting models to improve accuracy by reflecting the current conditions as well as providing even more granular historical data.

b. **Generation Planning:** The mix of power generation resources considering resource availability, cost, and environmental impact is impacted by multiple factors, including markets, state siting processes and energy policies, and/or utility planning in those cases where utilities remain vertically integrated. This can involve selecting appropriate technologies and locations for new generation facilities to ensure a reliable and sustainable power supply. Utilities employ capacity expansion and production cost models, such as Aurora and PLEXOS, where regions are typically divided into zones connected by interfaces. GETs can be integrated into generation planning by considering opportunities for interface transfer limit expansion. With DLR deployed, for instance, historical rating data can be input into the probabilistic models to inform more accurate rating assumptions if the interface is thermally limited. For topology optimization and APFC, planning studies can identify transfer capability expansion opportunities to consider in generation planning analyses. Planning studies with topology optimization can also identify transmission constraints that can be fully mitigated by reconfiguring the substation that a generator is interconnected into.

c. **Transmission Planning:** Designing the transmission network to deliver electricity reliably, including line capacity and redundancy considerations, is critical for maintaining system reliability and efficiency. This stage involves assessing current infrastructure and planning upgrades or new installations to meet future demand and expected system conditions. Tools like PSSE, TARA, DSATools, PowerWorld, PSLF, Aspen, PSCAD and EMTP-RV are employed by utilities and regional planning entities, including ISOs and RTOs, to perform planning analyses. Additionally, the use of production simulation modeling is used to evaluate system conditions to provide insights into system performance, reliability and economic benefits, helping the transmission planner assess the impact of new transmission projects or upgrades, quantifying savings from reduced congestion and evaluating the integration or renewables. Tools used for these studies include Plexos, PROMOD, GridView, OPF and PSO. GETs are system enhancements that complement traditional upgrades and can be more cost-effective depending on the magnitude of the need. DLR can be integrated into planning studies by, for example, increasing wind speed assumptions near wind farms assumed to be at a high-capacity factor. The wind speed values can be obtained from wind measurements from the nearby wind farm or other sensors installed near the transmission line. These can then be used as inputs for the DLR to adjust the real-time line capacity rating. Information developed by using DLR can also be used to identify which transmission components are the actual limiting factors over time, which can guide efficient investment. For topology optimization and APFC, their impacts on load serving or generation deliverability can be incorporated in solutions options analysis. FERC Order No. 2023 mandated the evaluation of certain technologies, including APFCs, in the interconnection cluster studies. [14]

d. **Operational Planning:** The development of operational plans is essential for outage maintenance scheduling and coordination, contingency planning based on studies performed during transmission planning, unit commitment and dispatch of any long-duration storage as well as real-time or intra-day operations. Operations planning studies typically leverage previously performed planning studies, including additional scenarios, to evaluate the impact of various outages and unit commitments and dispatch to ensure operational plans account for these system conditions. Topology optimization is particularly effective in the operational planning timeframe. Typical use cases include coordinating overlapping planned transmission outages, allowing planned transmission outages to be approved without degrading system reliability, and mitigating congestion impact due to planned and unplanned transmission outages.

   For real-time or intra-day operations, DLR can precisely measure actual conditions instead of relying on overly conservative assumptions to address thermal constraints, while topology optimization and APFC can maximize transfers for a given operating plan — all of which facilitate reliable operation and outage management. Ensuring the grid can handle real-time variations and contingencies with proper monitoring and demand response strategies is essential for maintaining stability. This includes managing load fluctuations, integrating renewable energy sources, and responding to system disturbances in real-time.

e. **Post-Event Analysis:** Reviewing system performance after events to improve future reliability and strategies is an important part of continuous improvement. Post-event analysis involves analyzing data from past incidents, identifying root causes, and implementing corrective actions to prevent recurrence and enhance system resilience.

The table below identifies the level of effort to integrate the technologies evaluated within this report in the transmission planning study process. Similar to all technology integration, the initial process will be manual with the goal to develop automated tools to complete the necessary integration and perform the respective study. The integration challenge ranges from 1 requiring the lowest effort to 5 requiring the most effort for Full Time Engineers (FTEs). For example, 5 is full-time work for 2 engineers for more than 1 year, 2 is full-time work for 1 engineer for less than 6 months. The weights provided below are based on the typical knowledge of transmission planning engineers.

Study	Tools	Type of Study (Manual or Automatic)	Integration Challenge (1-5) 5 = Most effort required		
			DLR	APFC	TTO
Power Flow/Steady State Analysis	PSLF, PSSE, PowerWorld, TARA DSATools PSAT/VSAT	Manual	2	3	3
Short Circuit Analysis	PSSE, TARA, PSLF, PowerWorld and DSATools PSAT/VSAT	Manual	N/A	3	3
PV/QV Analysis	PSSE, TARA, PSLF, PowerWorld and DSATools VSAT	Manual	N/A	3	3
Dynamic Stability Analysis	PSCAD, DSA Tools, PSLF, PSSE, PowerWorld, TARA	Manual	N/A	4	3
Electromagnetic Transient Studies	PSCAD and EMTP	Manual	N/A	4	3
Sub-synchronous resonance Analysis	DSATools SSAT, PSCAD and EMTP	Manual	N/A	4	3
Capacity Expansion and Production Cost Modeling	Plexos, Promod, Grid View, OPF, PSO/Enelytix	Manual	2	3	2

4 Dynamic Line Ratings Modeling

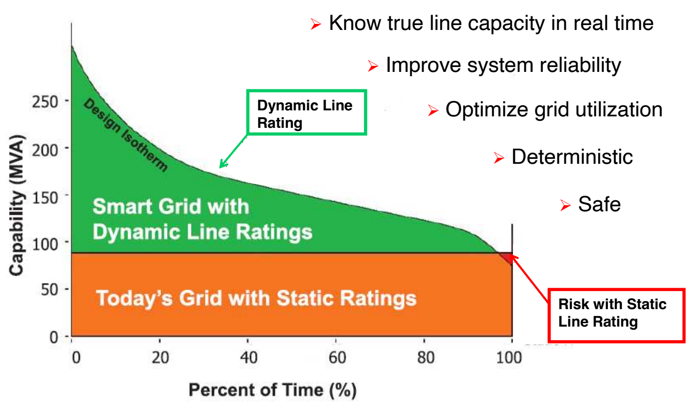
Dynamic Line Ratings provide real-time measured data on the capacity of transmission lines by considering factors like temperature, wind speed, and solar irradiance. This enables more accurate power system modeling by providing measured data on actual conditions rather than relying on conservative estimates. It enhances the grid's ability to manage variable renewable energy sources and optimizes the use of existing infrastructure. The process of optimizing transmission line capacities in response to changing environmental conditions involves several critical stages, each aimed at enhancing the efficiency and reliability of power transmission.

1. Data Collection	▪ Gather environmental data on historical weather and line position.
2. Modeling and Simulation	▪ Use collected data to simulate transmission line performance under various environmental conditions. ▪ Understand the impact of factors like wind speed and temperature on the line ratings.
3. Optimization	▪ Adjust operational parameters based on simulation results to maximize transmission line capacity and reliability. ▪ Example: DLR sensor platforms typically provide a variety of forms of data beyond those necessary for calculating DLR, which provide a range of opportunities for evaluating transmission system conditions that can help optimize grids.
4. Implementation	▪ Apply optimized settings in real-time grid operations to enhance capacity and manage variability. ▪ Conduct continuous monitoring and updating of line ratings based on real-time data.

Congestion Benefits and Cost Savings. DLR offers considerable opportunities for alleviating congestion by providing more accurate forecasts of expected transmission capacity. This accuracy facilitates better generator commitments in Day-Ahead markets and more efficient dispatch in Real-Time markets, thereby reducing congestion costs. Figure 4 illustrates the MVA potential of dynamic ratings compared to static ones, highlighting moderate congestion relief due to significantly increased capacity [15] [16].

Notably, capacity increases sometimes exceed 100% compared to static ratings, particularly on cloudy, windy days when solar irradiance is low, and wind cooling is high. Therefore, there is a particularly strong synergistic relationship between DLR and wind generation sources: high wind conditions result in both increased wind power generation and cooler transmission lines, which, with DLR, can transport more power from these wind resources [17]. Wind measurements from the nearby wind farm or sensors installed near the transmission line can be utilized as inputs for the DLR to adjust the real-time line capacity rating.

Figure 4. **Capacity Potential from DLR vs. SLR**



The implementation of DLR is widely recognized for its potential to manage congestion effectively, as evidenced by multiple studies. For instance, a 2018 study by PJM Interconnection (PJM) revealed that deploying DLR equipment on a single line could reduce congestion costs by $4 million annually [18], potentially resulting in savings for customers. Additionally, MISO's 2023 State of the Market Report found that utilizing AARs could have reduced congestion costs by $380.3 million in 2022 and $172.8 million in 2023, showcasing the significant cost savings potential also applicable to DLR due to their similar optimization of transmission line capacity based on real-time conditions [19]. These studies underscore the significant congestion management benefits and cost savings that DLR technologies can offer. Utilities that have implemented DLR state that the cost of implementing DLR is relatively low, making the return on investment (ROI) very attractive, increasing the visibility and likelihood of implementation in the future by other utilities.

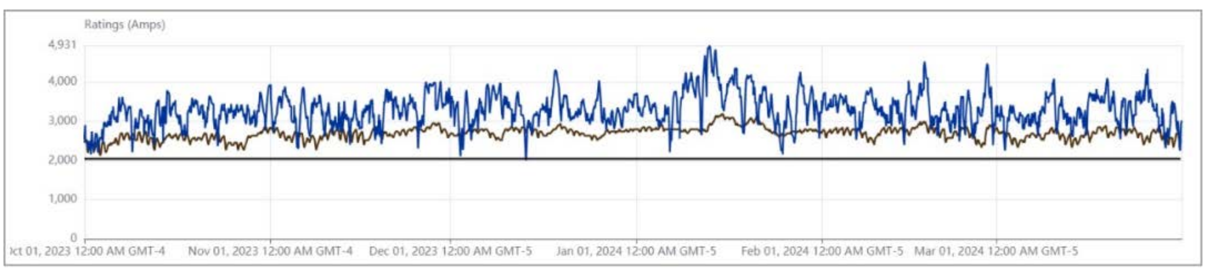
Utilities have recently begun to undertake larger-scale installations in the US, significantly enhancing the carrying capacity of existing lines by dynamically adjusting thermal ratings based on actual measured conditions. This year, AES has deployed

42 sensors across five transmission lines in Indiana and Ohio, and Great River Energy (GRE) deployed 56 sensors across ten transmission lines in Minnesota [20].

Such deployments can draw on a planning and evaluation approach that leverages existing weather datasets, such as those from the National Solar Radiation Database (NSRDB) and WIND Toolkit, to model in-specific DLR capabilities across large regions. Utilities and their vendors can also draw on computational tools to simulate and analyze DLR impacts on system reliability and congestion. For example, employing standardized methods, (e.g., IEEE738-2012) allows utilities to calculate line ampacities under varying conditions. Larger scale deployments may follow quickly from pilot projects that provide a basis for validating modeled predictions and assessing cost-effectiveness. Vendors already use the range of deployments made in their technologies to refine broader models, and utilities can also gain confidence from studying such deployments.

The results of DLR deployments show significant gains in capacity, as shown in Figure 5 below. Data from AES's initial DLR deployment reveals a consistent and significant headroom gain for the transmission line. Over a six-month period, the average DLR value was 3294 Amps, which is a 61% increase from the static rating. The median DLR value was 3279 Amps, a 60% increase, closely matching the average. The mode, or the most frequently occurring DLR value, was 3038 Amps, indicating a 49% increase over the static rating. The standard deviation from the mean was 13% [21].

Figure 5. **Time Series of Line 345kV-1 line Ratings, Including DLR, AAR, and Static Ratings**
(DLR is in blue, AAR is in brown, and static ratings are in black)



GRE's initial deployment of four sensors showed a 48.92% mean capacity increase with DLR, versus a 7.19% median increase with AAR. Further modeling by GRE showed a potential $3.157 million in congestion costs per event on any one line, leading it to quickly follow up its successful pilot with its larger deployment. Integration with system dispatch has also come a long way, with GRE having integrated its DLR ratings not only with its internal energy management system, but also with MISO's Inter-Control Center Protocol (ICCP).

Dozens of other similar demonstration deployments are described in reports from the Idaho National Laboratory [22] and industry research reports [23] There are scores of operational DLR deployments around the world, with some utilities deploying DLR systemwide. Further examples are listed in Section 8. These examples underline the potential of DLR, with a dynamic and robust modeling framework, for inclusion in planning and operational studies to enable greater transmission efficiency, improved resource allocation, and better alignment with real-time environmental factors. The analysis of historical environmental data coupled with projected weather and grid conditions will enable the development of forecasts of DLR as well as allow for the inclusion of risk metrics associated with these ratings.

As the grid evolves and the penetration of variable renewable generation, such as wind and solar, increases, the associated uncertainty and intermittency further emphasize the importance of DLR in managing congestion effectively.

Improved Situational Awareness. DLR systems play a crucial role in enhancing situational awareness. The sensors required by DLR systems can also monitor asset health, providing transmission owners with information on the line conditions and the estimated remaining lifespan of assets. For instance, DLR sensors can offer quick insights into the effects of icy conditions or nearby wildfires. Additionally, as depicted in the "Risk from Static Line Rating" section of Figure 4, DLR can detect times when line ratings should be lower than those calculated by static methods. This is particularly useful on extremely hot days with high solar exposure and no wind, where DLR can help system operators identify lines that are loaded beyond their real-time capability, thereby mitigating risks. Furthermore, DLR data can support wildfire prevention strategies by informing grid operation practices and the timing for vegetation clearing or equipment upgrades, thus enhancing both situational awareness and safety [24].

Accelerating Grid Modernization. DLR has the potential to significantly advance grid modernization on the transmission system. It offers enhanced flexibility during extreme events and provides additional tools for grid operators. For example, during extreme cold weather that causes equipment malfunctions and outages, operators can use the colder temperatures to channel more power through certain lines, thereby mitigating or eliminating the adverse effects of the event. This approach increases the reliability and resilience of grid infrastructure. Moreover, long-term DLR data can provide valuable insights into line performance, helping to identify at-risk power lines that are prone to causing wildfire sparks. Overall, the widespread deployment of DLR technologies greatly strengthens resilience, reliability, and flexibility within the grid [19].

4.1. USE IN PLANNING STUDIES

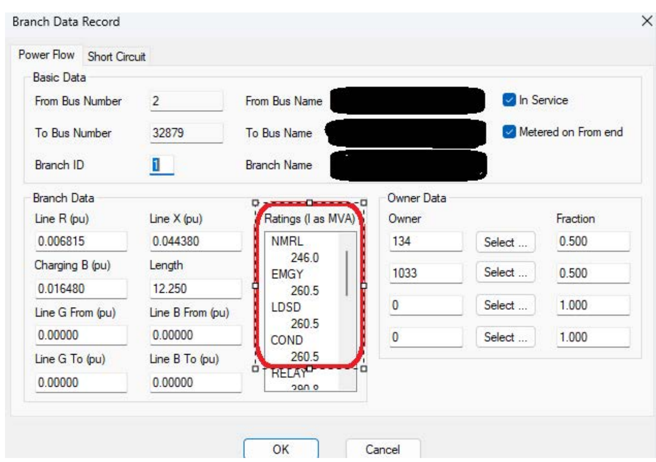
Today DLR is more commonly used during real-time system operation, allowing the operation engineers to observe in near-real-time transmission line ratings based on existing system conditions, i.e., temperature, wind speed, thermal loading, etc., to maximize the transmission line's capacity to carry additional generation and load safely and efficiently. For safety reasons, we sometimes operate below the maximum DLR rating, ensuring an added margin to account for unexpected changes in system conditions (i.e., wind stops blowing or changes direction).

The DLR rating can be added alongside other transmission line rating options, such as static and ambient adjusted ratings, within power system modeling software. Considering its main ability is to determine the transmission line rating under different conditions, it is only applicable to be used during steady state studies where thermal violations are being evaluated. For DLR to be used in transmission planning or interconnection studies, an iterative simulation approach is necessary for the completion of the steady state study. First, the planning engineer will perform the traditional steady-state study, assuming the generation dispatch, load dispatch and additional generation to be included as well as a list of necessary contingencies, i.e. N-1, N-1-1, N-2, etc., to be evaluated. Upon completion of these studies, the results may conclude that there are thermal violations. The results of the analysis will identify the specific thermal loading of the transmission line, i.e. line is rated for 100 MVA and the loading for the scenario is 150 MVA, allowing for the transmission planner to know the minimum loading necessary for alleviating the thermal overload and providing. These thermal violations will then be evaluated further to determine if DLR could be utilized to identify additional thermal capacity of the transmission line that could result in relieving the thermal violation.

Once DLR is selected as an option to be evaluated to relieve the thermal violations, utilities will proceed in calculating the thermal carrying capacity of the overloaded transmission lines based on the best and worst weather conditions for a given scenario being analyzed to obtain a minimum and maximum current carrying capability. To evaluate the transmission line in question, the planning engineer would utilize historical weather data in the area of the transmission line and proceed to calculate the weather-adjusted line rating of the transmission line based on these conditions utilizing existing standards [25]. The weather information and calculations can utilize existing tools from NREL [26] [27], that allow for an estimation of the line rating based on these historical conditions. Further tailoring can then be performed based on the conductor type and specifications to develop a more representable rating for the transmission line in question. The minimum and maximum current ratings are evaluated to understand the full range of the transmission line to better understand any risk associated with the ratings utilized during the evaluation. Next the thermal violation scenarios will be evaluated through the use of the minimum and maximum thermal ratings through an automation method to adjust the thermal ratings of the transmission lines during the steady state study to evaluate the ability of the DLR to relieve the thermal violations. The automation, typically Python scripts, would adjust the line ratings during the contingency analysis to evaluate the before and after adjustment of the line rating. Figure 6 shows the value that would be adjusted in PSSE through the Python Application Programming Interface (API). The additional automation would be considered minimal compared to the likely in place automation tools for completing the steady state contingency analysis. It should be noted that automation is not necessary to evaluate line ratings, however its implementation into existing automation scripts used by transmission planners would be straightforward. It should be noted that the simulation of the electrical network and the calculation of the transmission line rating are performed in different software platforms.

Once the updated line rating has been determined, it can be implemented within the transmission planning tool to restudy and confirm that the thermal overloading has been mitigated. Caution needs to be taken during this evaluation as the weather conditions are a major driver of the capacity at any given time and thus the capacity may not be available during a time of need. This will lead to the need for further data analytics to more accurately identify the generation and load profiles along with the surrounding weather conditions to understand if DLR would be a viable option.

Figure 6. **PSSE Screenshot Demonstrating the Change of a Transmission Line Rating**



4.2. FUTURE OUTLOOK: VENDOR AND INDUSTRY PERSPECTIVE

DLR technology is poised to play a transformative role in modernizing ISO/RTO operations and enhancing grid efficiency. As the energy sector transitions to accommodate higher renewable energy penetration and increased electrification, DLR offers a data-driven solution to optimize grid utilization and reliability. Additionally, DLR complements other GETs, such that the calculated thermal ratings can be an input for TTO and APFC to obtain a more effective operating system condition. Vendors have expressed strong commitments to supporting TOs, ISOs/RTOs and regulators in understanding and implementing DLR, emphasizing the importance of a collaborative approach to maximize its benefits. These vendors are optimistic about the future of DLR, recognizing that with the right support and collaboration, the challenges currently faced can be effectively addressed. By working closely within industry stakeholders, vendors are confident that the adoption of DLR will lead to significant improvements in grid efficiency and reliability, ultimately paving the way for a more resilient and dynamic energy system.

The adoption of DLR is supported by significant industrial interest and offers numerous benefits, positioning it as a transformative solution in the energy sector. While its implementation involves manageable challenges, these are surmountable with targeted strategies and industry collaboration, setting the stage for widespread deployment of DLR.

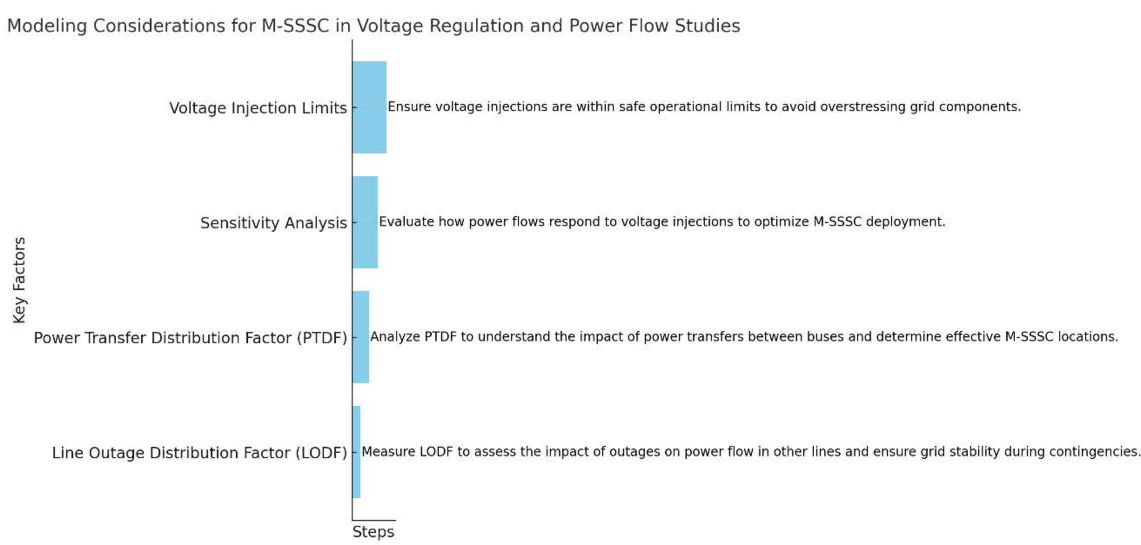
Economic Opportunities	▪ DLR has the potential to enhance grid efficiency and maximize existing infrastructure, aligning with the industry's goals for cost-effective solutions. Addressing incentive structures and investment classifications can make DLR more attractive to transmission owners, unlocking its full economic potential. While operational considerations such as the potential impact online lifespan exist, this impact has been documented as manageable with proactive maintenance and operational strategies [19]. ▪ Ongoing studies are demonstrating DLR's advantages over simpler solutions like AARs, reinforcing its value proposition in both performance and innovation.[10]
Enhancing Data Reliability	▪ DLR data is largely accurate, and efforts to improve measurement and modeling are currently ongoing which will lead to increased operator confidence. [10] ▪ These advancements highlight the industry's commitment to delivering robust, reliable and actionable insights from DLR data, fostering greater trust and adoption.

Empowering Operational Readiness	▪ Transitioning from SLR to DLR requires an investment in operator training, new software and updated processes, leading to valuable opportunities to enhance operation expertise. ▪ Support for training programs and collaboration between vendors and ISO/RTOs helps overcome the initial complexity and drive successful implementation. As operators become more familiar with DLR, its integration into control operations will become more seamless.
Global Adoption and Growing Industry Advocacy	▪ The energy industry is supporting more pilot projects and demonstrations that showcase DLR's ability to increase grid capacity. These initiatives provide valuable evidence for the technology's effectiveness and scalability. ▪ While there is significant support for DLR among network stakeholders, technical, market, and regulatory challenges need to be addressed for wider implementation [28]. ▪ Vendors echoed the need for regulatory mandates, such as FERC Order 881, to drive adoption, emphasizing the financial benefits and importance of internal champions within utilities.

5 Advanced Power Flow Control Modeling

APFC devices provide dynamic , which is essential for maintaining stability and reliability in a grid increasingly reliant on renewable energy sources. Additionally, they can provide damping capabilities to alleviate a variety of oscillations that may occur due to dynamic and transient events. Thus, APFC devices are studied in steady state, dynamic and transient analysis depending on the event to be evaluated. Some of the major vendors of APFC devices have phasor domain, i.e. PSSE, PSLF, SSAT, TARA, etc. and Electromagnetic Transient (EMT), i.e., PSCAD, EMTP-RV, etc., models necessary for performing planning and operational studies, however most of the models to date are still under development and adjustments in the software of study are necessary to evaluate the technology accurately. Figure 7 below outlines the key factors to be considered and evaluated when considering an APFC as a solution. Different scenarios are needed to evaluate the impact of the APFC as well as the control functions needed to ensure efficient operation and performance [29].

Figure 7. **M-SSSC Modeling Process**



Phasor domain software requirements for steady-state voltage stability and electromechanical stability analysis encompass several essential aspects. Accurate modeling of voltage profiles is crucial to maintaining voltage levels across the grid within acceptable limits during both normal and contingency operations. Furthermore, real-time monitoring and control capabilities are needed to adjust voltage levels and ensure stability. Advanced simulation tools also play a vital role, as they can simulate electromechanical dynamics to predict system behavior under various conditions [30].

For transient analysis and Sub Synchronous Oscillation (SSO) related analysis, EMT modeling requires high-fidelity simulation tools to capture fast dynamics effectively. Integration of real-time data and robust control algorithms is critical for managing transient and oscillatory behaviors in the grid. These tools must be capable of accurately representing the electromagnetic interactions and potential oscillations to maintain stability and reliability during dynamic events.

The implementation of APFC brings substantial benefits to the power grid. It enhances voltage regulation, reduces congestion, and improves overall efficiency and reliability, facilitating the integration of renewable energy sources and ensuring stable grid operations. Dynamic voltage regulation and power flow control provided by APFC improve grid stability. This technology also offers operational flexibility, allowing for frequent adjustments without significant maintenance costs. By optimizing power flow, APFC reduces congestion and enhances capacity, presenting a cost-effective alternative to traditional infrastructure upgrades and reducing capital expenditure.

5.1. USE IN PLANNING STUDIES

APFC's can play a vital role in addressing a variety of system violations that result in the need for system upgrades. Thus, modeling APFCs accurately in all relevant applications is crucial to understand their impact on the system under study. These devices can be evaluated simultaneously with DLR to provide firm, weather-independent mitigation for thermal violations with their ability to control the line (limit or increase) current across multiple transmission lines. Lastly, by providing different types of controlled responses, these devices can dampen oscillations caused by voltage instability, active power instability and subsynchronous resonance.

As previously mentioned, models for these devices, and like other FACTS (Flexible AC Transmission Systems) devices, require engineering judgment and adequate training for use in transmission planning studies. Additionally, the complexity of these models due to their controls and ability to respond to a variety of system events and scenarios makes the implementation and studying of these devices more involved. Their capability to solve multiple issues with a single solution means that care must be taken to ensure all benefits are identified and the scale of a project solution is minimized. However, through proper training and discussion with the software platform providers and vendors, the planning engineers can accurately model these devices as alternative solutions to typical transmission upgrades.

APFC's can be used in steady state analysis to relieve thermal violations by redirecting current through parallel transmission lines to optimize flow within the respective area. A steady state analysis will be performed by the planning engineer assuming the generation dispatch, load dispatch and additional generation to be included as well as a list of necessary contingencies, i.e. N-1, N-1-1, N-2, etc., to be evaluated. Upon completion of these studies, the results may conclude that there are thermal violations. These thermal violations can be evaluated for the use of M-SSSC's to alleviate these violations. To implement APFC's within steady state studies, typically an automation model is provided by the vendor or integrated within the planning software directly. The APFC model detects the conditions of the transmission line upon which it is deployed and adjusts its voltage injection (and therefore line reactance) to meet the targeted current flow on one or more transmission lines. There are various parameters and settings that can be adjusted to obtain the best solution for the use of the APFC. APFC's can be coupled with DLR in steady state studies to ensure firm utilization of the higher carrying capacity of a DLR-equipped transmission line and optimize power flow across multiple transmission lines to better serve the system.

Dynamic studies may also be required when APFCs are used as a solution to address dynamic issues. Similarly to the steady state study, a dynamic study utilizing the same scenarios and contingencies is performed to evaluate the dynamic stability of the system. This study is more complex due to the nature of the models utilized to represent all equipment, i.e., conventional generators, inverter-based resources (IBR), wind turbines, etc., within the system. The accuracy of each of these facility models is critical in understanding the overall system impact. The dynamic study performed may determine that there are voltage oscillation and collapse concerns that could be resolved by APFC devices through active damping controls and redirecting of power flow.

Also, by adjusting various parameters within the APFC model, system oscillations and system instability could be addressed thus alleviating the need for more costly traditional upgrades or curtailment of generators.

Lastly, the implementation of APFC's to alleviate system resonances has recently been discussed when resources cannot do so on their own. This type of study is typically the most challenging and time consuming to perform due to the complexity of the network models and associated control interactions. APFC models are available from the vendors and have been validated with hardware-in-the-loop (HIL) protocols to ensure their simulated responses to system events match hardware performance. To perform an EMT study to evaluate the APFCs ability to resolve any resonance event, one will need to identify from the steady state and dynamic study of interest as well as the respective models used for the study. Typically, these studies will be conducted where there is a high penetration of IBRs or series compensated lines nearby. Once the area has been determined, the steady state model will need to be translated to the EMT simulation space through typical industry tools or manual development. Once the base system model has been developed, the respective nearby generation, load and APFC EMT models are added to the system model. Some regions already have EMT models of the areas where system resonance or weak grid situations occur and thus these models can be used as a starting point for implementing the APFC model. Once the base case has been set up and the initial conditions match the steady state cases, the various system faults can be performed to evaluate any potential for system resonance conditions. Similar to the dynamic stability study, specific parameters within the APFC model can be adjusted to dampen out any oscillations or mitigate the oscillations all together. These studies may take up to several weeks to complete. Additionally, the technical expertise to set up and evaluate these studies is extensive and greater training is needed for engineers to perform these studies with confidence.

APFC also has the potential to combine deployments with widespread regional measures. In planning studies, local and regional APFC deployments can be set to automated adjustment when solving a case. Consideration should be given for adjacent APFC deployments to adjust their control parameters and/or enable additional controls for more advanced operation.

APFC is also capable of increasing the value of new infrastructure like new lines, rebuilds or reconductoring. Often, the flow through a new line is limited by the N-1 conditions of existing parallel lines. For example, a new 500 kV system can be limited by the 230 kV system that runs in parallel. In the case of reconductoring, changing the conductor does not guarantee that all the power will flow through the reconductored line. Directing flow from other parallel lines into the newly reconductored line will often provide more value and can further increase the transfer capacity across a set of lines.

5.2. FUTURE OUTLOOK: VENDOR AND INDUSTRY PERSPECTIVE

APFC technologies can transform utility operations and grid management. By enhancing grid flexibility, accelerating renewable energy adoption and delivering significant financial benefits, these technologies enable utilities to address evolving system demands while optimizing existing infrastructure. Addressing adoption barriers through education, standardization and software integration will be critical to unlocking its full potential. Utilities that prioritize these innovative technologies will be better positioned to meet the demands of the evolving energy landscape while ensuring long-term operational success.

Flexibility and Adaptability	▪ One of the unique advantages of APFC's devices is their flexibility, which allows them to solve multiple problems over time. This flexibility often poses challenges in initial economic assessments but provides long-term benefits as the system evolves. ▪ APFCs offer the benefit of adaptability. They can address various issues like power flow control and voltage stability, providing ongoing value as system requirements change over time.
Renewable Integration and Grid Modernization	▪ APFC solutions accelerate the integration of renewable resources by enabling faster deployment and reducing customer costs. ▪ GETs enhance interconnection capacity through existing infrastructure, allowing for increased trade across market areas and further financial benefits.
Operational Readiness and Financial Benefits	▪ Implementing APFCs can lead to significant financial gains by offering more efficient solutions compared to traditional methods. For example, replacing end-of-life phase-shifting transformers with APFC devices can provide a more cost-effective and efficient alternative. ▪ The ability to deliver solutions earlier (within one to two years) enables faster connection of additional renewable power, resulting in reduced costs for consumers and financial rewards for utilities. ▪ Vendors provide extensive training for utilities, covering planning, control room operations, fieldwork, and maintenance. This training ensures that all relevant personnel are equipped to handle the technologies effectively throughout their lifecycle.
Overcoming Adoption Barriers	▪ Existing modeling techniques are adequate but need integration into core software platforms like PSSE, PSLF, and TARA. This integration would enhance efficiency and reduce the training burden on utilities. ▪ There is a need for standardized approaches to planning, controlling, and operating these technologies to reflect recent advances. This standardization would facilitate broader adoption and reduce the burden on individual utilities. ▪ Lack of product education regarding the capabilities as well as lack of education on how to use models that are available for studying within typical planning software. ▪ Utilities would benefit from a side-by-side articulation of the differences and similarities between APFC devices and Series Capacitors.

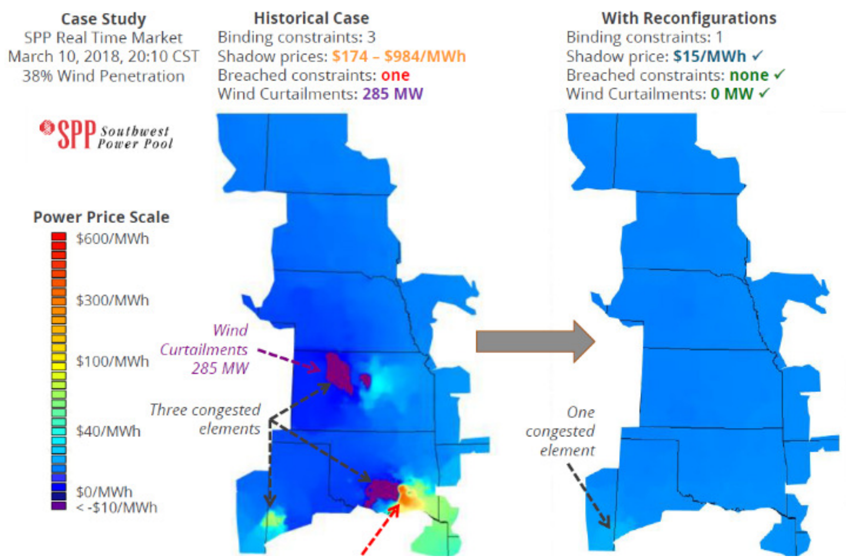
6 Topology Optimization Software Modeling

Topology Optimization Software enhances system reliability and efficiency by reconfiguring the grid's layout to optimize power flow. This method significantly reduces congestion and boosts the grid's resilience using existing hardware. By enabling better management of power flows and facilitating the integration of renewable energy sources, which are often variable and dispersed, this software plays a crucial role in modern grid management.

There are several stages of analysis for integrating topology optimization into the planning and operational phases. The initial assessment involves evaluating current grid performance and identifying areas needing improvement. This is followed by simulation and modeling, where models are created to simulate different topology configurations and their impact on grid performance for both planning and operation horizons. The optimization stage uses algorithms to determine the optimal grid configuration that minimizes congestion and maximizes efficiency. The next step is to assess the results of the topology optimization solution for the event or scenario evaluated to determine if the solution is viable for the condition studied. These solutions can then be implemented either as an automated solution to be used in real-time or as an operational solution within the operating guides to be implanted under specific system conditions, i.e., planned outages, seasonal operation, etc. Finally, topology optimization should be continuously assessed to extract maximum benefit, ensuring that a change previously implemented remains optimal for a different set of system conditions.

Improving Operational Challenges. Topology optimization deployment by grid operators, especially ISOs and RTOs, will assist operations, reduce congestion, and minimize renewable curtailment. This technology is particularly effective in the operational timeframe. The software tool can be deployed in offline mode within days, set up similar to planning simulation tools to aid the operator in making decisions during outage situations based on previously studied or real-time studies completed by the tool that the operator will need to implement manually. The tool can then be integrated later into the full operations environment to allow for automated solutions during system events. Integrating topology optimization into grid operations offers significant improvements and can alleviate congestion. A 2018 study by the Southwest Power Pool (SPP), shown in Figure 8, applied topology optimization to a small portion of their region in the Midwest to reduce wind generation curtailment, lower costs, and improve contingencies [31]. This study is one of many that illustrates the potential applications of topology optimization. Other studies include a PJM analysis identifying a 50 percent reduction in real-time congestion costs [32].

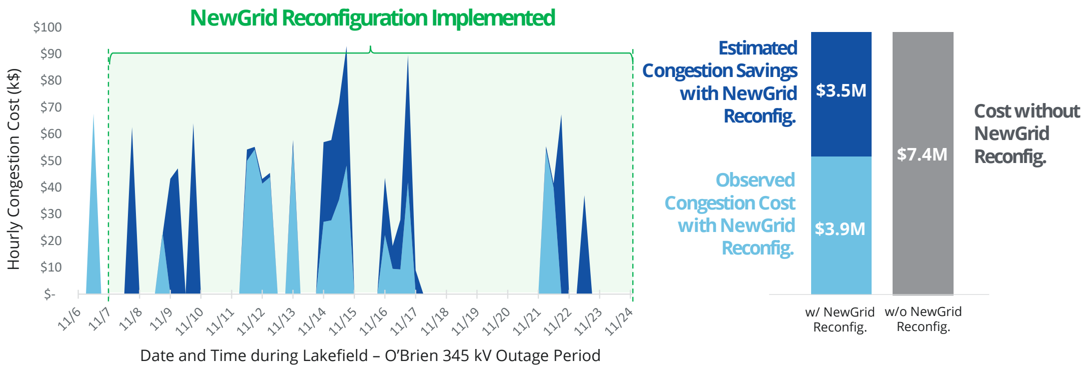
Figure 8. **SPP Study Detailing Congestion and Curtailment Relief Using Topology Optimization**



Improving Planning Challenges. As the current electric grid undergoes transformation, topology optimization emerges as a crucial tool for system-level planning. This technique can be employed to reduce or eliminate violations, minimize outages, and bolster system reliability. In certain situations, system planners might leverage topology optimization strategies to manage disasters or unforeseen events by adjusting the grid's topology in real time. This approach helps maintain system performance without incurring additional costs or violating operational constraints, such as N-1 contingencies [33]. Specifically, topology optimization could be used to meet NERC TPL-001-4 planning events.

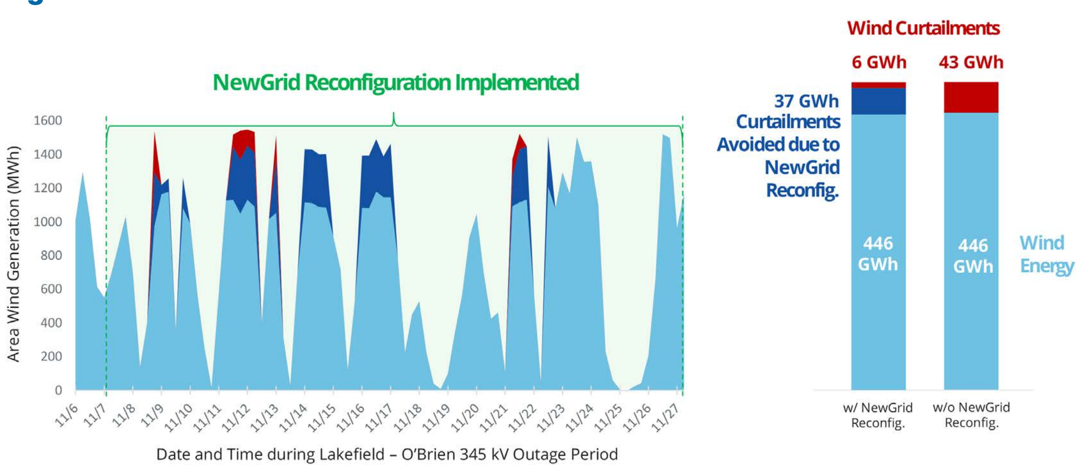
Congestion Cost Savings. In November 2023, a major 345 kV line across the Iowa/Minnesota border was under planned maintenance for three weeks. A reconfiguration solution developed and requested to MISO by NewGrid on behalf of MISO members ahead of the outage start was implemented and reduced regional congestion costs by $3.5 million over the three-week outage, as evaluated ex-post using all available state estimator snapshots during the period and shown in Figure 9 below. The associated production cost savings were $1.1 million [34].

Figure 9. Congestion Cost Savings



During the outage, the total generation by the area wind sites was 483 GWh. The reconfiguration reduced wind curtailments by 86% (37 GWh of wind) over the three-week period, as shown in Figure 10 [35].

Figure 10. Reduced Wind Curtailments



6.1. USE IN PLANNING STUDIES

Topology optimization can be utilized to reconfigure the system in an optimal way to reduce or resolve select system violations. The number of configurations that can be evaluated are subject to the original configuration of the network and the ability to switch circuit breakers to reconfigure substations and connect or disconnect transmission lines. Thus, it may not always result in a total resolution of the issue observed but could reduce the severity of the event and then coupled with DLR and APFC could completely resolve the system issues in lieu of traditional upgrades or temporarily while the upgrades are deployed.

Utilizing topology optimization in transmission planning studies requires a topology optimization software package. Manual topology optimization would be a daunting task with the traditional simulation software platforms utilized for transmission planning due to the myriad possible grid reconfigurations, thus resulting in the need for a robust automation tool to perform this evaluation. There are existing tools available that allow for this automation and calculations to be performed outside the traditional tools and then utilize these results to update existing studies to determine the system impacts, i.e., thermal, short circuit, dynamic, etc. Topology optimization can be utilized to relieve steady state and dynamic system violations. Each of the necessary steady state or dynamic studies is performed as traditional studies with the implementation of the topology optimization algorithm via an automation script accounting for the ability of the system to implement different reconfigurations as well as any additional constraints that the ISO/RTO or other transmission planning entity may impose to meet planning criteria (e.g., a maximum load radialization amount).

Topology optimization is typically evaluated as a solution to resolve system congestion, thermal overloads, optimizing the current flow within an area based on load and generation, and also gives the grid operator the ability to further isolate faults and reduce short circuit current through reconfiguration. The implementation of the topology optimization solutions is very simple and only requires switching a typically reduced number of circuit breakers. This is an action that can usually be performed by control centers via SCADA, although there can be switching operations that require local actions at the substation.

The transmission operator needs to specify the scenarios under which the reconfigurations would need to resolve the violations or would in general need to perform well (e.g., not create other violations). For example, if there is a transmission violation that only materializes in one planning scenario, but there are also other planning scenarios, the reconfiguration could be tested under the single scenario in which the violation that the reconfiguration resolves materializes. Alternatively, the transmission may also be required to perform well under the remaining scenarios that do not exhibit the violations, assuming that the reconfiguration would be adopted as the new normal topology.

Topology optimization may be particularly applicable to mitigate violations of more challenging transmission events, such as those resulting from P6 (N-1-1 events), P7 (common mode failures) and Extreme Events as identified through the completion of NERC TPL-001-4 studies. These planning events occur rarely in operations, and as such traditional solutions developed for these would be significantly underutilized. If these needs can be met by reconfigurations, the capital allocated to transmission investments could be devoted to other projects that would have higher utilization.

In addition to developing alternatives to traditional projects, topology optimization can be used to inform traditional transmission expansion project portfolios. For example, it can be used to determine which projects provide more transmission flexibility value, and to identify the relative value of different substation arrangements.

Topology optimization can be utilized in other types of studies as well, such as EMT to evaluate options for reconfiguration that may increase the system impedance such that it could resolve resonance issues that may have resulted from a system event.

6.2. FUTURE OUTLOOK: VENDOR AND INDUSTRY PERSPECTIVE

TTO is poised to significantly enhance the efficiency and reliability of power systems. By enabling rapid identification of optimal network configurations, these tools facilitate effective power flow management and congestion mitigation. The future will likely see further integration of advanced algorithms and learning-based approaches, contributing to a more efficient and sustainable system.

Benefits	▪ **Low cost and high benefits:** Reconfigurations typically incur minimal costs, often referred to as "no-cost solutions," while offering significant reliability and economic benefits. For instance, the savings is often 1,000 times larger than the cost of switching, based on input from circuit breaker maintenance providers. ▪ **Wide geographic coverage:** The NewGrid software can provide benefits by optimizing for the entire RTO footprint, including large RTOs such as PJM or MISO, with a single deployment. ▪ **Efficient upskilling of existing workforce:** NewGrid provides training when licensing their software. The software is designed to be user-friendly, requiring only about half a day of training, making it accessible for engineers with varied levels of experience. ▪ **Incremental deployment:** The software can be deployed in offline mode for planning and operations planning or integrated with the EMS for real-time operations support. Offline mode deployment can be deployed within days and plug-and-play into existing operations planning business processes, since the inputs are in standard formats. ▪ **Improved operations:** The existence of optimal reconfiguration processes can significantly enhance operational efficiency and ensure consistent application of best practices across different scenarios.

Concerns and Adoption Barriers	▪ The need for internal champions within grid operators to drive adoption. ▪ **Lack of established reconfiguration processes:** Detailed processes are needed for both planning and operations to ensure reliability during reconfiguration of the network. ▪ **Computational demands:** Topology optimization in production simulation modeling can be a computation-heavy exercise that may limit its integration in production simulation planning software. Reconfiguration solutions may need to be identified external to these software packages and be used as inputs for the simulations, instead of incorporating the topology optimization as decision variables in production simulation. ▪ **More frequent breaker replacement or breaker upgrades:** Increased breaker operations due to topology optimization may impact the longevity of the few devices that may be optimal to switch with more frequency and may increase the risk of breaker failure contingencies. Most switching solutions are driven by a fraction of transmission outages, however, and thus the increased switching duty of most breakers is of a similar or lower order of magnitude as the number of planned transmission outages in the area. ▪ **Grid operators' perception and preferences:** Operators may be under the impression that there are limited further opportunities to extract value from transmission systems beyond existing practices. Further, operators tend to be risk averse, slowing down the adoption of new technologies. ▪ **Misaligned incentives:** For transmission operators, the low-cost nature of the technology could be viewed negatively as not providing sufficient revenues to justify trying the technology.
Future Outlook and Recommendations	▪ Encouraging grid operators to adopt new topology optimization processes can be driven by highlighting the benefits of reduced congestion costs, improved reliability, and enhanced resilience. Different ISOs/RTOs and utilities may respond to different aspects of these benefits. ▪ Adoption of topology optimization technology varies between the transmission owner or operator. Some, like Alliant Energy, have seen significant benefits, including a 50% reduction in net congestion costs for their customers in Iowa over two years. Real-time implementation is still in development, such as the Electric Reliability Council of Texas (ERCOT) and ISO New England running NewGrid's software for operations planning rather than in control rooms for real-time operations. ▪ MISO, SPP, and ERCOT either already have or will soon have reconfiguration request process in place. Other ISOs/RTOs should develop similar processes to leverage the opportunities that this technology provides.

7 Interconnected Modeling

The interconnected modeling of DLR, APFC, and TTO software involves integrating their functionalities into a unified grid management system. This integration can be achieved by:

- **Data Integration:** Combining real-time environmental data from DLR with power flow data from M-SSSC.
- **Coordinated Control:** Using TTO algorithms to adjust grid configurations dynamically based on inputs from DLR and APFC systems, including co-optimizing the M-SSSC and other power flow control equipment setpoints.
- **Simulation Models:** Developing comprehensive simulation models that incorporate the operational characteristics of all three technologies to study their combined impact on grid reliability and efficiency.

The effort required for integration can vary depending on the specific technology and the existing infrastructure of the utility as well as the level of experience the engineers have with integrating new technologies thus emphasizing the focus and need for continuous training. DLR and APFC might require a higher initial effort due to the need for new sensors and control systems, while TO might be easier to integrate incrementally as it primarily involves software upgrades and system reconfigurations.

8 Successful Case Studies and Applications of GETs

There are several real-world case studies highlighting successful applications of DLR, APFC, and TTO software in power system studies:

Dynamic Line Ratings (DLR):

- **Great River Energy:** After a successful trial of 4 sensors in the fall of 2023 which increased mean capacity by 48.92% (as compared to an AAR mean increase of 7.19%), GRE installed 52 more sensors across 10 of its transmission lines in Minnesota. GRE also successfully integrated its deployment into its energy management system and into the MISO's ICCP.
- **AES Corporation:** AES installed 42 sensors across five transmission lines in Indiana and Ohio, significantly enhancing the carrying capacity of existing lines by dynamically adjusting thermal ratings based on actual conditions. The deployment resulted in increased line capacity, enhanced situational awareness, and cost-effective deployment.
- **SUMO Software (ELES Slovenia):** Implemented DLR software that provides real-time thermal ratings for network components. This technology mitigated over 550 network events annually and increased capacity by a median of 15-20%.
- **PJM Interconnection:** Applied DLR on one line, leading to significant cost savings and increased transmission capacity. DLR enabled PJM to handle higher loads without immediate infrastructure upgrades, facilitating the integration of renewable energy sources. The study demonstrated the potential for substantial cost savings and enhanced capacity, improving the grid's ability to manage variable renewable energy sources.
- **Idaho National Laboratory:** Demonstrated significant increases in line carrying capacity and improvements in grid reliability and safety through various DLR deployments. The laboratory's guide to case studies of DLR highlights several successful deployments, showing increased capacity and grid reliability improvements.
- **Oncor DLR Project:** Conducted from January 2010 to May 2013 with a budget of $7,279,166, this project aimed to alleviate transmission constraints and integrate dynamic ratings into real-time operations across five 345 kV and three 138 kV transmission circuits in Texas. Using 27 Nexans CAT-1 units and additional monitoring systems, the project achieved real-time capacity increases up to 200% (capped at 125% for protection), successfully integrated dynamic ratings into ERCOT's

operations, and demonstrated the commercial viability of DLR systems despite challenges like data anomalies and financial verification difficulties.

- **The NYPA (New York Power Authority) Project:** Conducted from January 2010 to January 2013 with a budget of $1,440,000, aimed to assess DLR technologies and their correlation with wind generation across three 230 kV lines in northern New York. Utilizing video sagometer systems, ThermalRate systems, EPRI sensors, and weather stations, the project achieved real-time capacity increases of 30-44% and demonstrated a positive correlation between wind farm output and line rating. Key insights highlighted the importance of reliable DLR data and addressing cybersecurity concerns. Despite data accuracy and instrument performance challenges, NYPA plans further DLR deployments and is investigating coupling DLR with phasor measurement unit data.

Advanced Power Flow Control (APFC):

- **Central Hudson Gas & Electric Corp.:** Collaborated with Smart Wires Inc. to deploy M-SSSC devices on the Leeds-Hurley Avenue line, meeting a 21% series compensation requirement. This project avoided issues related to subsynchronous resonance (SSR) and reduced the impact on protective schemes compared to traditional Fixed Series Capacitors (FSCs). This project opened up 185 MW of transmission capacity.
- **Victoria to New South Wales Interconnector (VNI) Project:** Used Modular Power Flow Control (MPFC) equipment to increase transfer capacity and optimize power flow, resulting in cost savings and enhanced network resilience.

Transmission Topology Optimization (TTO):

- **ERCOT and ISO New England (ISO-NE):** ERCOT and ISO-NE have been using topology optimization software to support operations planning decision making processes, including to develop constraint management plans (ERCOT) and to support outage coordination and impact mitigation (ISO-NE).
- **MISO, SPP, ERCOT:** MISO introduced a reconfiguration request process, in which market participants can send a reconfiguration solution to be analyzed by MISO and TOs, and if approved, implemented by MISO. In its first year, the process has approved a number of reconfigurations that saved the region millions of dollars. SPP and ERCOT have approved and are implementing similar processes, planned to be in place in 2025.
- **Alliant Energy (Interstate Power and Light):** Implemented topology optimization with NewGrid, leveraging the MISO reconfiguration request process, resulting in a 49% reduction in net congestion costs over two years, saving their transmission customers $24 million (with additional savings for other transmission customers in the region). The effort identified reconfigurations that could further reduce congestion costs by another 31% if implemented consistently.

- **SPP Market:** Successfully used topology optimization to mitigate congestion on a key transformer during high load conditions. The reconfiguration provided about a 20% reduction in constraint flow, improving reliability during peak periods.
- **Evergy: I**mplemented a reconfiguration in its footprint that provided full relief on a constraint that was binding 48% of the time. The reconfiguration delivered significant congestion and reliability benefits.
- **Winter Storm Elliott (2022):** SPP implemented two transmission reconfigurations that released up to 845 MW from otherwise stranded generation, significantly alleviating congestion during the storm.

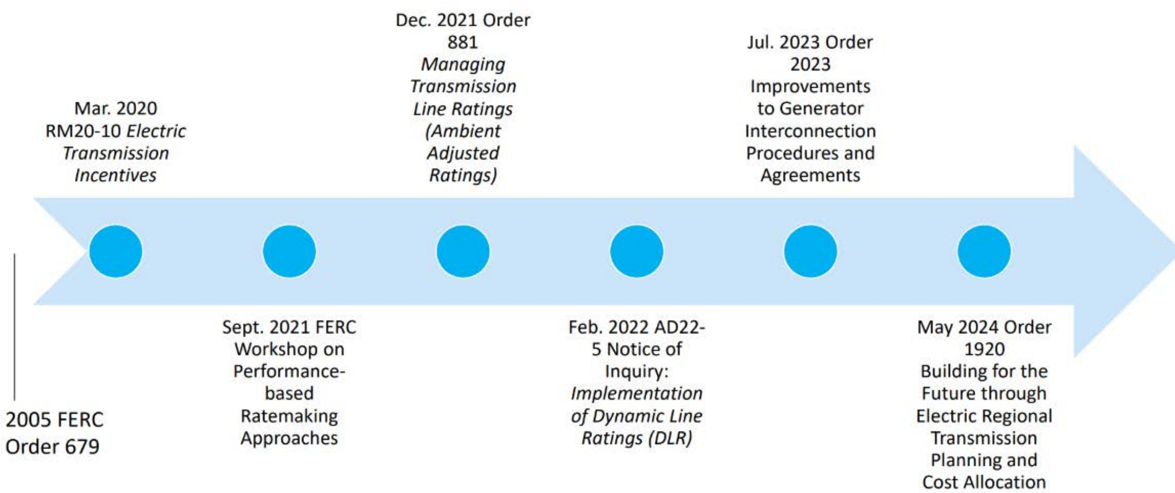
The Brattle Group's Analysis: Demonstrated that combining topology optimization, dynamic line ratings, and power flow control devices in Kansas and Oklahoma could reduce congestion and more than double the headroom for interconnecting renewable resources

RMI (PJM Study): Conducted a study on the use of Advanced Power Flow Control (APFC) in PJM, finding that APFC could mitigate network congestion and increase the potential for renewable energy interconnections with costs recoverable in as little as six months.

9 Compliance and Standards

Through several rulemakings, FERC has taken some steps to promote GETs, described below and depicted in Figure 11:

Figure 11. **Timeline and Key Developments in FERC Orders and Policies Related to Grid-Enhancing Technologies (GETs)**



Order No. 679, issued in 2006, established the foundational principles for transmission incentive policies, but did not require incentives for advanced transmission technologies and found that such incentives should be evaluated on a case-by-case basis. The WATT Coalition and Advanced Energy United submitted a proposal to FERC in 2020 for an electric transmission incentive targeted to GETs, which was then discussed at a 2021 FERC workshop [36]. But FERC has not taken any further action on GETs-focused transmission incentives.

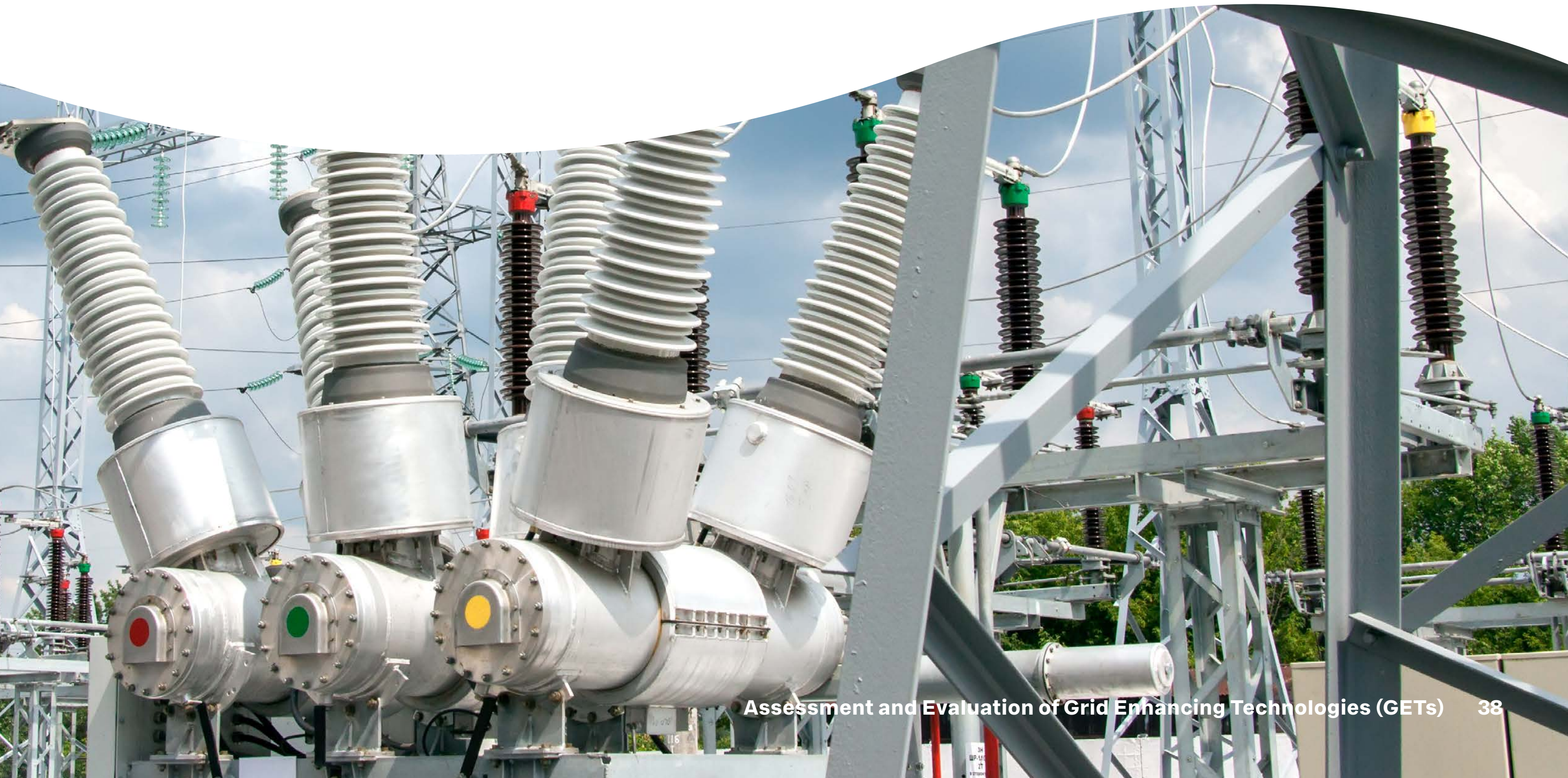
Order No. 881, issued in 2021, mandated the implementation of ambient-adjusted ratings (AAR), as discussed previously, emphasizing the importance of accurate and real-time data for grid management. FERC also established a three-year deadline from the date of the compliance filings for transmission providers to implement AARs and emergency ratings.

A subsequent **Advanced Notice of Proposed Rulemaking (ANOPR)**, issued in 2024, explored potential requirements for the implementation of dynamic line ratings (DLR) that reflect solar heating on all transmission lines and that reflect wind speed and direction on certain lines that exceed wind speed and congestion thresholds.

Order No. 2023, which required certain interconnection process reforms, required GETs to be integrated into the solutions considered in interconnection studies.

Order No. 1920 requires transmission providers to evaluate dynamic line ratings, advanced power flow control devices, advanced conductors, and transmission switching as part of the current and new long-term transmission planning processes.

With GETs poised to be integrated in the transmission planning and interconnection processes, it will be beneficial for TOs, ISOs/RTOs and technology developers to continue their dialogue on the operational and market implications of GETs integration, ensuring benefits are realized in practice. For instance, from a market perspective, what ratings should Day Ahead Markets consider for circuits equipped with DLR? Operationally, what procedures would support a more fulsome role out of topology optimization? Providing an end-to-end perspective on the value and operationalization of GETs would further reinforce their benefits and facilitate a broader and more expeditious adoption rate.



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