Topology Control & Optimization

Grid Enhancing Technologies: Technical Reference Guide

2024

For Public Use

Purpose

PJM supports the transparent, cost-effective, efficient and reliable deployment of Grid Enhancing Technologies (GETs) and Alternative Transmission Technologies (ATTs) on the PJM system consistent with requirements of PJM's governing documents and manuals. PJM seeks to raise awareness of GETs applications and benefits without overstating their ability to supplant necessary transmission investment. However, the details within this guide may not be perfectly applicable to every project proposal, subset of the technology, transmission zone, or local and state regulations. Rather, the guide seeks to provide a broader understanding for the technology's background, technical and modeling considerations, potential benefits and barriers, as well as regulatory context.

This technical reference guide is intended to aid the evaluation of topology optimization software and understanding of topology control in the PJM region. Topology optimization is not specific to individual transmission facilities, but instead is the act of determining the optimal use of the transmission system based on system conditions. By contrast, topology control (also referred to as transmission switching), focuses on opening or closing transmission elements in pre-determined circumstances based on prior analyses in advance of the operational time horizon.[1]

PJM cannot prescribe topology optimization system installations, nor the use of transmission switching, but provides criteria to consider when evaluating such proposals.

Background

Topology control is far from new to the operation of the PJM grid and is used to redirect power flows by switching transmission elements in and out of service (commonly referred to as switching solutions in PJM). This switching is done in order to reduce or eliminate congestion costs while maintaining reliability. Traditionally, switching solutions were identified and studied based on their respective scenario in coordination with Transmission Owners (TOs) based on operator/engineer expertise and leveraged manual simulation processes. PJM operations augments its reliability studies and real-time assessments with derived topology control solutions for PJM and its TOs for consideration.

PJM publishes a list[2] of pre-identified and confirmed transmission switching options that have been identified to provide market transparency. While switching solutions continue to be found by PJM and member engineers and operators, PJM utilizes Real-Time Topology Control (RTTC) software that runs every 15 minutes, or ad hoc, to suggest switching solutions based on current system conditions. Correspondingly, a study version exists for the tool for use in the operations planning time horizons up to real time. These derived topology control options may or may not be feasible based upon system conditions, either projected or actual, or due to impacts beyond the view of the PJM operations model and ultimately are implemented solely at the discretion of PJM and its TOs.

Topology optimization advances the practice of manually identifying topology changes by programmatically determining optimal localized network topology configuration on a period-by-period basis. PJM's software solution allows for continuous evaluation of localized network topology reconfiguration options and recommends both pre-identified solutions as well as actions that may not have been previously identified. Either pre-identified, or new,

[1] FERC Order No. 1920 ¶ 1,246 at 884

[2] PJM.com, Markets & Operations, PJM Tools, Switching Solutions

actions are suggested where appropriate and where system reliability is maintained while providing awareness around any potential post-contingency islanding that a solution might induce.

In terms of long-term usages, PJM Manual 7: Protection Standards[3] describes scenarios in which topology control may be utilized via Remedial Action Schemes (RAS). Whereas "normal" protecting relaying systems are typically designed to isolate faulted elements, a RAS may take seemingly unrelated actions such as the tripping of local or remote system elements (including generators), generator runback and topology control via system reconfiguration and/or load shed.

NERC defines a RAS as a scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a system(s). A RAS accomplishes objectives such as:

- Meeting requirements identified in the NERC Reliability Standards
- Maintaining bulk electric system (BES) stability
- Maintaining acceptable BES voltages
- Maintaining acceptable BES power flows
- Limiting the impact of cascading or extreme events

Thus, RAS are a viable pre-determined topology control solution, and when armed, are a dynamically implemented topology control solution, where appropriate.

Technical Considerations

Technical considerations should be evaluated in terms of proposed uses for topology optimization and/or topology control. Pursuant with FERC Order 2023 and FERC Order 1920, PJM considers topology control as an operational tool used to evaluate the entirety of the PJM footprint and interaction with our neighbors. Based on the purpose of topology optimization software as compared to topology control (described in sections below), PJM feels that topology optimization should not be utilized as a unique solution to an identified planning problem. Consistent with FERC suggestions, this software should be leveraged as a more holistic approach to operating the system in and near real time.

PJM operations has topology control software in place today to both identify benefits from known transmission switching as well as make recommendations around potential new transmission switching to alleviate constraints in the real-time and near-term time horizons. Regardless of the means in which the suggested transmission switching is recommend (manually or via topology control software), PJM recommends that proposed transmission control procedures be circumscribed to those which:

1 | Are utilized in the operations planning, Same-day operations and real-time operations time horizons[4]

2 | Are associated with generator deactivations that must include a defined termination date

[3] PJM Manual 7: Protection Standards

[4] See NERC Time Horizons (PDF)

3 | Are approved by all appropriate Transmission Owners (TOs) and are transparent to all impacted parties by inclusion within appropriate documents[5]

4 | Acknowledge the need for study and coordination with TOs prior to action

(a) This includes acknowledgement that switching solutions may not be implemented by PJM based upon system conditions, either projected or actual, and ultimately are implemented solely at the discretion of PJM and its TOs.

5 | Reflect the associated costs of operating equipment in terms of asset management in association with the forecasted frequency of use

Projects that meet one or many of the above technical considerations do not necessitate the use of transmission control, but rather suggest a consideration of possible use and further evaluation.

Topology Control & Optimization – Evaluation Matrix

	In Use in PJM Today	Potential Opportunity	Not Currently Applicable
Congestion Management	▲		
Thermal Support	▲		
Voltage Support	▲		
Stability Support	▲		
Generation Interconnection			▲
Economic Planning		▲	
Long-Term Reliability Planning			▲

[5] PJM Manual 3B: Transmission Operating Procedures (CEII) and/or PJM.com, Markets & Operations, PJM Tools, Switching Solutions

Modeling Considerations

The use of topology optimization, or topology control software, is dependent on the ability to integrate the software across PJM's operations and markets systems. This includes, but is not limited to, the integration with PJM's:

- Energy Management System (EMS) and associated systems
  - Transmission Network Application (TNA)
  - eDART
  - Supervisory Control and Data Acquisition (SCADA)
  - Intelligent Event Processing (IEP)
  - Transmission Adequacy & Reliability Assessment (TARA)
  - Transient Security Assessment (TSA)
- Market systems including the day-ahead market clearing engine

Once a proposed transmission control solution is identified, PJM, impacted TOs and neighbors must be able to model and study impacts of the proposal. PJM is able to model proposed transmission switching (whether identified manually or via topology control software) based on the existing equipment in the PJM EMS.

Potential Benefits

The goal of topology optimization is to automatically identify viable and beneficial system reconfiguration options by evaluating the current state of the system. Ideally, topology optimization would allow for the following:

- Increased operational flexibility
  - Allow for a reduced or lowest cost response to system constraints
  - Accommodate transmission or generation outage requests that may otherwise be denied
- Lower generation costs
  - Reduce or eliminate congestion
  - Reduce or eliminate barriers to full use of transmission capacity

By optimizing the reconfiguring of network topology, system operators would be able to achieve least-cost operations based on real-time or near real-time conditions. The software would reassess the network topology as conditions change and continuously determine what the optimal network topology should be based on actual real-time conditions and potential future grid conditions including:

- Changes to load and generation patterns
- Planned equipment outages
- Planned equipment returns to normalized state

Beyond use in real-time operations, absent the additional benefits of utilizing topology optimization in combination with the Day-Ahead Market, increased uplift would be incurred. PJM recognizes this issue, and pre-identified topology control solutions are incorporated into its Day-Ahead Market today. Likewise, for topology optimization, Day-Ahead Market incorporation would need to include projected switching solutions in order to directly inform the market of planned next-day operations. The forecasted ability to identify controlling actions could reduce congestion and allow for increased utilization of least-cost generation and transmission capacity, which could have significant market impacts across the PJM system.

Identified Barriers

While the concept of topology optimization might seem straightforward, there are several factors that must be considered when evaluating the implementation and use of software of this nature. As a regional transmission organization, PJM must coordinate all suggested topology changes with the necessary impacted parties before any action is taken in order to fully understand their impact and anticipated changes to the near-term operation of the grid. There are several reasons why a switching solution may not be feasible and the continuous coordination between PJM, TOs and Generation Owners (GOs) is critical to ensuring system reliability. With the essential coordination, solutions cannot be automatically implemented without understanding, acknowledgement and confirmation from the operator and engineering staff.

PJM's operational and market models have bounds and limitations, beyond which they cannot see impacts. While the models themselves have bounds for the purposes of simplification and speed, the underlying distribution networks are challenges that require coordination when identifying potential new solutions to avoid placing such under/non-observable networks at risk. Assuring stability issues and cascading are avoided can be challenging for a tool designed for topology optimization to even begin to assess. Weather can also play a role in making a topology control solution not worth the risk for customer impact, as many solutions can take customers out of a networked configuration and into a post-contingency radial load shed situation. Depending on the device, it might not be designed to be in a normally open state for a prolonged period absent clearance being provided by its line and bus disconnects, thus requiring expanded coordination and personnel. These concerns, along with other network reliability factors (e.g., issues during re-energization), must be evaluated by tools that can perform such assessments via PJM–to-member coordination and/or through operator and support staff coordination.

The continuous evaluation of network topology for larger systems can be computationally complex and may require significant investment in order to become operational. Full-blown topology optimization and the added dimension of a non-predetermined transmission topology would strain the timeline of PJM's Day-Ahead Market. It is also important to understand what the impact of topology changes have on existing market constructs and neighboring system conditions. While changes may allow for outage requests, or reduce system congestion, it may shift a problem, or some level of congestion, to another part of the system at a time frame that is not predictable ahead of the times it is run. Similarly, introducing topology uncertainty to any forward projecting forecasts can impact the financial transmission rights (FTR) market, with topology optimization potentially determining winners/losers leveraging systems that are not easily simulated by market participants.

Transmission switching can often be viewed as a non-cost solution to alleviate a problem on the system. In reality, there are costs associated with switching electrical equipment in and out of service. Operating equipment does have an impact on the life of an asset and may increase associated maintenance costs. This consideration is increasingly complex if the identified equipment switching is not owned by the same entity as the beneficiaries. While these costs may be minimal when the switches are done infrequently, an increase in the number of operations on a piece of equipment needs to be accounted for within the broader evaluation of system control. Likewise, taking an otherwise networked system and placing load and assets into radial post-contingency de-energization pockets repeatedly, for the purposes of generating lowest cost overall, places such facilities into a risk with which they are likely to neither have a stake in the determination nor potentially the benefit. Such decisions can be justified when done for system reliability, but less so when reliability is not truly at stake and reduced costs are the aim.

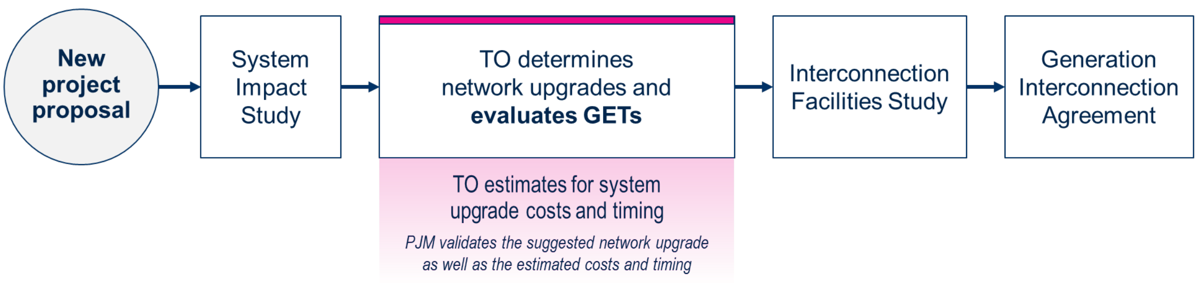
FERC Order 2023

On July 28, 2023, the Federal Energy Regulatory Commission (FERC) issued Order 2023,[6] a Final Rule adopting reforms to address interconnection queue backlogs and promote new technologies through its forms of generator interconnection procedures and agreements. In addition to ordering reforms to implement a first-ready, first-served cluster study process, the Commission addresses reforms to incorporate technological advancements into PJM's interconnection process. The Final Rule requires transmission providers to evaluate, though *not* deploy, alternative transmission technologies in their cluster studies such as static synchronous compensators, static VAR compensators, advanced power flow control devices, transmission switching, synchronous condensers, voltage source converters, advanced conductors and tower lifting including any in any studies and re-studies.

The Final Rule emphasizes that the transmission provider will retain the sole discretion to determine consistent with good utility practice, applicable reliability standards and other applicable regulatory requirements. It is important to note that FERC Order 2023 requires the evaluation of "transmission switching" and does not specify the use of topology optimization. This is an important distinction in terms of the application and evaluation across PJM processes.

The Final Rule also requires that transmission providers include in their feasibility study reports and system impact study reports an explanation of the results of the evaluation for each of the aforementioned alternative transmission technologies for feasibility, cost and time savings as an alternative to a traditional network upgrade and whether a specific alternative technology should be used. **Figure 1** details when GETs are evaluated within a simplified generation interconnection process.

Figure 1. Simplified Generation Interconnection[7] Flowchart Considering GETs



[6] FERC Order No. 2023

[7] Generation Interconnection Fact Sheet, PJM Interconnection

PJM seeks an independent entity variation with respect to the Final Rule's requirement that transmission providers include in interconnection study reports the results of their evaluation of the feasibility, cost and time savings of GETs as an alternative to traditional transmission technologies.

In accordance with PJM's FERC Order 2023 and 2023A compliance filing,[8] the PJM Tariff already accounts for alternative transmission technologies in the interconnection process, as all of the enumerated GETs already are considered and studied, as necessary in the course of interconnection studies in the PJM region.

Within the generation interconnection process, PJM does not view transmission switching as a viable permanent solution to identified network upgrade requirements. This does not, however, preclude the identification of topology switching that could impact future operation of generators within the interconnection process. This identification may combat future congestion resulting from the generator output, but is not to be used as a replacement of a network upgrade needed to alleviate identified violations within the interconnection study process.

FERC Order 1920

FERC Order 1920[9] requires transmission providers to consider dynamic line ratings, advanced power flow control devices, advanced conductors and transmission switching for each identified transmission need in long-term regional transmission planning (LTRTP) and existing FERC Order 1000 regional transmission planning processes. The Order requires transmission providers to consider each of the enumerated technologies when evaluating new regional transmission facilities, as well as upgrades to existing transmission facilities, and explain in sufficient detail why any of the enumerated technologies are not selected. The selection and use of any of the technologies that are incorporated into an existing transmission facility should be treated as an upgrade to an existing transmission facility. Therefore, an incumbent transmission owner would be designated. For a new selected regional transmission facility, the transmission developer (incumbent or nonincumbent) is designated.

As in FERC Order 2023, FERC Order 1920[10] once again specifies the required evaluation of "transmission switching" and not topology optimization. PJM is prepared to account for the operation and study of transmission switching in compliance with FERC Order 1920.

A key consideration is that benefits for all projects be calculated on the same time horizon to allow for the ability to properly compare projects.[11] As such, PJM will require a time horizon that covers, at a minimum, 20 years starting from the estimated in-service date when comparing proposals within the LTRTP process. Projects including alternative transmission technologies proposed in an Order 1000 window will be evaluated over existing time horizons. As with all GETs, PJM recommends that proposals evaluate the technical considerations laid out in this technical reference guide as it applies to the identified issue.

[8] Order Nos. 2023 and 2023-A Compliance Filing of PJM Interconnection

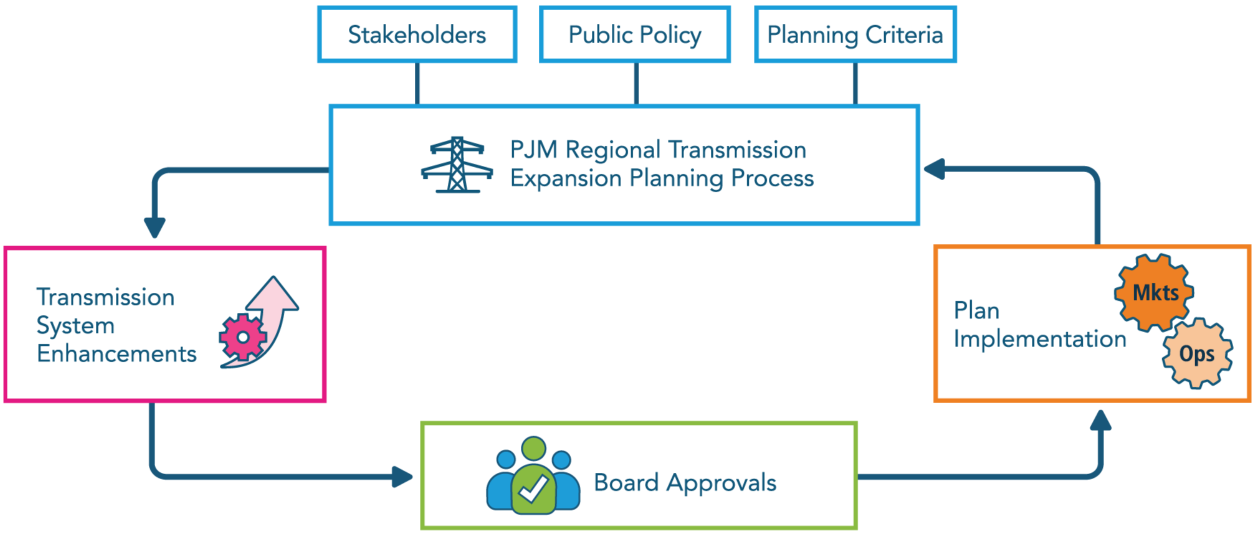
[9] FERC Order No. 1920: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, 187 FERC ¶ 61,068, at P 187

[10] FERC Order No. 1920, ¶1198

[11] FERC Order No. 1920, ¶848

Within the Regional Transmission Expansion Plan (RTEP), it is incumbent on the proposing entity to evaluate and suggest the use of transmission switching, or any other GETs. As described in **Figure 2**, PJM receives input from states and other stakeholders, and in conjunction with the planning criteria, identifies the baseline projects. Proposing entities are then able to submit, for PJM consideration as part of the RTEP process, transmission system enhancements that may include, among other things, transmission switching and GETs.

Figure 2. RTEP Process – RTO Perspective



Within long-term planning, PJM views transmission switching as a temporary solution, and one that should not be viewed as a permanent solution to an identified problem. As such, PJM recommends that these solutions be used in combination with additional long-term proposals when timing is of the essence. Generator retirements with identified reliability violations requiring system upgrades where the identified long-term solutions cannot be put in place prior to said retirement are opportunities in which switching solutions may be utilized in the interim. Once long-term solutions are in place, the switching solution should no longer be needed or utilized unless additional requirements are identified.