



Working to Perfect the
Flow of Energy

THE BENEFITS OF THE PJM TRANSMISSION SYSTEM

Appendices

PJM Interconnection

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Appendix A: RTEP Process Primer

Regional Scope

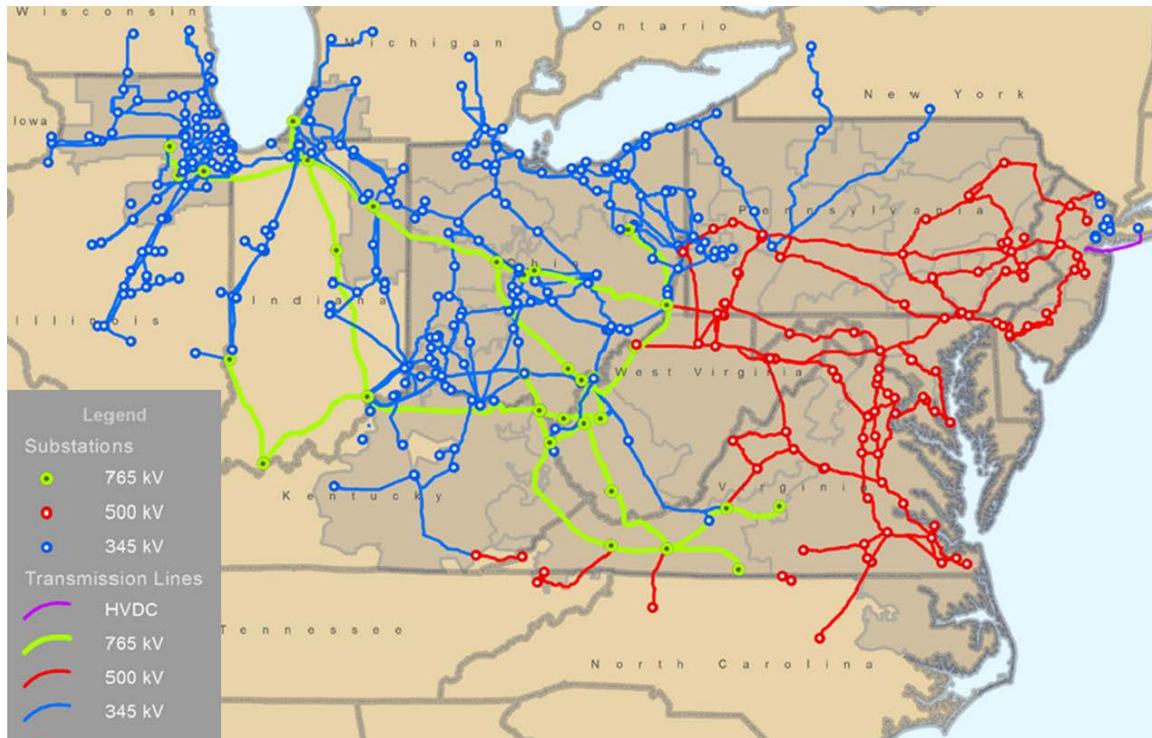
PJM Interconnection's Regional Transmission Expansion Plan (RTEP) process identifies transmission system additions and improvements needed to serve more than 65 million people throughout 13 states and the District of Columbia. The PJM system includes key U.S. Eastern Interconnection transmission arteries, providing members access to PJM's regional power markets as well as those of adjoining systems. Collaborating with more than 1,040 members, PJM dispatches more than 180,000 MW of generation capacity over 84,200 miles of transmission lines. PJM operates and plans the transmission system as though it were a single system. Corporate and state boundaries are not considered when taking operational action or making planning decisions. PJM has no financial or ownership interest in any PJM member. PJM's role as a federally regulated regional transmission organization (RTO) means that it acts independently and impartially in operating and planning the regional transmission system and in overseeing the wholesale electricity market.

PJM's RTEP process spans state boundaries across the RTO footprint, as shown in **Map 1**. This regional scope gives PJM the ability to identify one optimal, comprehensive set of solutions to resolve reliability criteria violations, operational performance issues and congestion constraints. Specific system enhancements are justified to meet local reliability requirements and deliver needed power to more distant load centers. Once the PJM Board of Managers approves recommended system enhancements – new facilities and enhancements to existing ones – they formally become part of PJM's overall RTEP. The PJM Board approval obligates designated entities to implement those plans. PJM recommendations can also include removal of previously approved projects if expected system conditions have changed such that justification no longer exists. A 15-year long-term planning horizon allows PJM to consider the aggregate effects of many interacting drivers, including:

- Reliability criteria violations
- Market efficiency
- Operational performance
- Requests for new service – generator interconnection, merchant transmission interconnection, long-term firm transmission service, etc.
- Generator deactivations
- Long-term congestion hedging (ARRs)
- Impacts of public policy mandates
- Interregional planning

Transmission projects that address one driver frequently also address others that alone did not justify the need for a system enhancement.

Map 1. PJM Backbone Transmission System



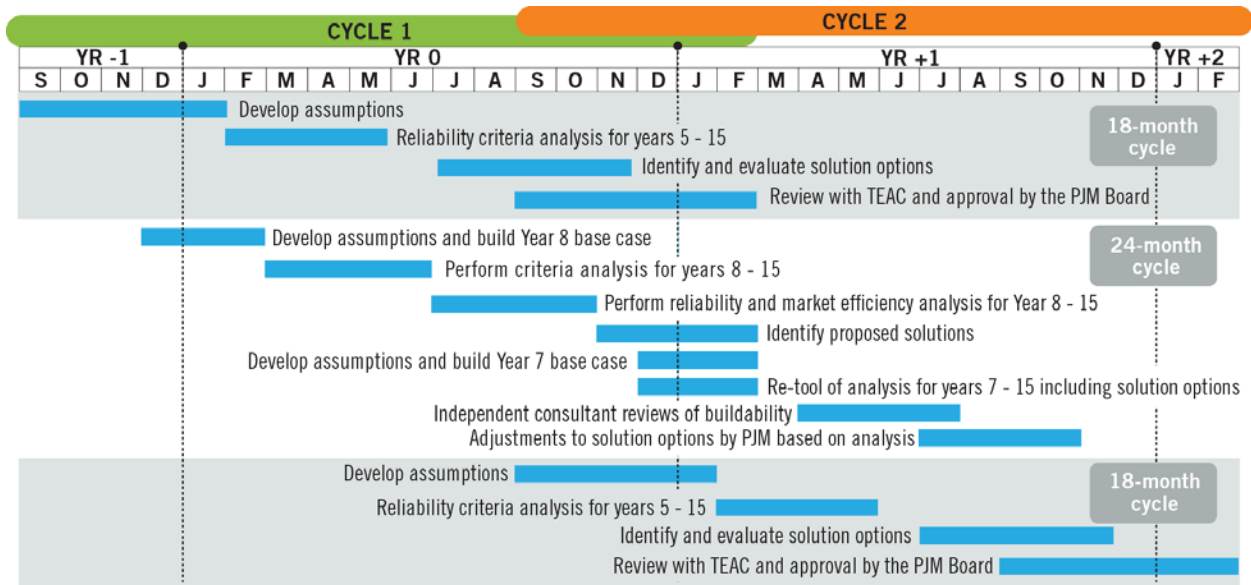
Planning Cycle

PJM's 24-month reliability planning cycle shown in **Figure 1** incorporates the following:

- Two 18-month cycles, each of which examines near-term transmission expansion planning needs – years one through five. The first 18-month cycle begins in September of the previous calendar year and extends through a full calendar year to the February of the next calendar year.
- One 24-month cycle, which examines long-term transmission expansion planning needs – 15-years forward

This 24-month planning process identifies system enhancements based on a number of studies: baseline, new service including generation interconnection, generation retirement, market efficiency and operational performance. These studies are conducted consistent with established NERC, regional and transmission owner criteria. Proposed system enhancements are reviewed with stakeholders through the activities of the TEAC and recommended to the PJM Board for approval.

Figure 1. 24-Month Reliability Planning Cycle



Power Flow System Modeling

PJM's RTEP process study cycles drive power flow model development. Credible, consistent power flow study results ensure PJM can develop robust transmission solutions to identified reliability criteria violations. To accomplish this, each study cycle begins with baseline analysis performed on a power flow case model that includes the latest information and assumptions with respect to zonal load forecasts, generating resources, transmission topology, demand resources and power transfer levels with adjoining systems (known also as interchange). PJM vets those assumptions with stakeholders through TEAC and subregional RTEP committee stakeholder in-person meeting and online forums.

Simulation Tools and Supporting Files

PJM employs a number of models and methodologies to create and maintain RTEP study simulation models. Base case creation, though, necessarily remains a collaborative process among PJM, transmission owners and generation owners, who update starting-point case files provided by PJM. PJM uses commercially available software for modeling, standard power flow analysis and for more complex analysis, such as generator deliverability. Supporting contingency files, monitor files, subsystem files and unit availability data are updated each year. *Contingency files* contain the sets of transmission facility outage combinations to be studied. Monitor files identify facilities to be analyzed for potential reliability criteria violations. All PJM bulk electric system facilities, tie lines to neighboring systems and lower- voltage facilities operated by PJM are monitored. Thermal and voltage limits are consistent with those used in operations as described in PJM Manual 3, Transmission Operations.¹

¹ PJM Manual 3, Transmission Operations: <http://www.pjm.com/-/media/documents/manuals/m03.ashx>.

Subsystem files identify source-sink pairs modeled in deliverability analysis area power transfers.

Unit availability files contain probability data to establish peak-load test condition dispatch scenarios in deliverability studies. These files play a crucial role, ensuring that reliability criteria violations are accurately identified.

System Topology

Each year, PJM creates and maintains a series of power flow cases that provide the basis for baseline, market efficiency, new service request, scenario studies and other analyses. In order to develop a 20yy study year power flow case, PJM removes its portion of the most recent multiregion modeling working group 20yy case and replaces it with its own internally developed model to reflect internal transmission topology changes (as approved by the PJM Board), generation additions, generator deactivations, bus load, interchange schedule and other modeling parameters. Queued generation projects are included in RTEP power flow case models if they have received a completed System Impact Study and have executed a Facilities Study Agreement (FSA) or Interconnection Service Agreement (ISA). Generators that have officially notified PJM of deactivation are modeled offline in RTEP base cases for all study years after the intended deactivation date, though such units are only removed from power flow case models one year after their actual deactivation date.

Interchange

Interchange values reflect expected net power transfers across one of PJM's interfaces with adjoining systems. Power flow case interchange levels reflect PJM Open Access Same-Time Information System² (OASIS) reservations for long-term firm transmission service with rollover rights. Doing so ensures that RTEP analyses are modeling cross-border transfers at levels consistent with those expected in actual operations. Indeed, such transfers may include transactions sourced from areas beyond systems immediately adjoining PJM. Interchange values are developed by comparing Eastern Interconnection Reliability Assessment Group³ (ERAG) case contractual interchange with PJM OASIS values. Any differences are reconciled by scaling generation and load accordingly.

Bus Load

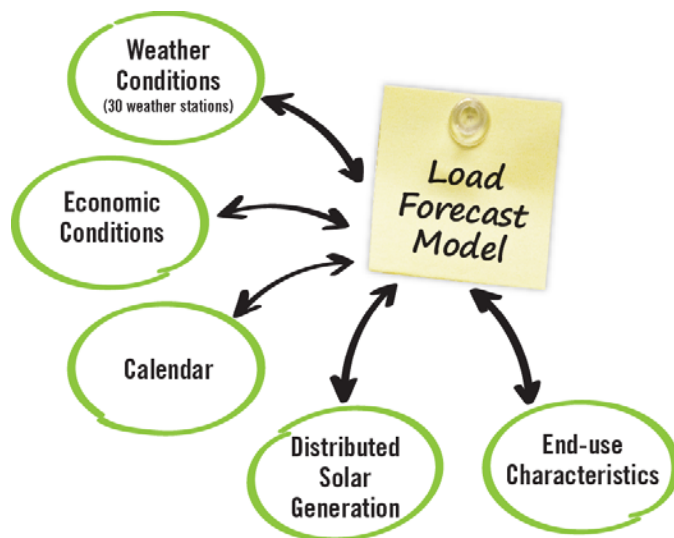
PJM transmission owner (TO) zonal load forecasts are the basis for power flow case bus loads. Modeling load this way is essential if transmission expansion studies are to yield plans that will continue to ensure reliable and economically efficient system operations. As a starting point, in order to develop a power flow base case model, PJM assigns zonal load – from its annual January PJM Load Forecast Report – to individual zonal buses according to ratios of each bus load to total zonal load; ratios are supplied by each transmission owner. Specifically, for load deliverability studies, zonal load is modified to account for load diversity, generally lowering the overall peak load in each area, given that peak loads in different geographical areas happen at different times (i.e., are non-coincident).

² PJM's OASIS provides information about available transmission capability for point-to-point service and a process for requesting transmission service on a non-discriminatory basis. Once a transmission service request is received on OASIS, PJM evaluates it to determine if sufficient capability to accept the request and ensure reliable service to all customers.

³ The ERAG is responsible for developing all Eastern Interconnection power flow and dynamic base case models, including seasonal updates to summer and winter power flow study cases.

PJM's annual load forecasting process yields a 15-year forecast assuming normal weather for each PJM zone and the RTO. The model estimates the historical impact of load (peak and energy) from a range of different drivers including weather variables, economics, calendar effects, end-use characteristics (equipment/appliance saturation and efficiency) and distributed solar generation, shown in **Figure 2**. The model is described in more detail in PJM Manual 19, Load Forecasting and Analysis.⁴ Additional specifics are available in PJM's load forecast white paper.⁵

Figure 2. PJM Annual Load Forecast Development



Demand Resources

PJM accounts for demand resources⁶ (also known as load management) by adjusting its base, unrestricted peak load forecast by the amount that clears Reliability Pricing Model (RPM or capacity market) auctions. Those amounts are reflected in each annual January Load Forecast Report for each transmission owner zone. The adjusted forecast is then used in RTEP power flow model development.

⁴ PJM Manual 19, Load Forecasting and Analysis, available on PJM's website:

<https://www.pjm.com/~media/documents/manuals/m19.ashx>

⁵ PJM load forecast white paper: <https://www.pjm.com/~media/library/reports-notice/loadforecast/2016-load-forecast-whitepaper.ashx>

⁶ A demand resource encompasses the ability to interrupt retail customer load that can be interrupted at the request of PJM. Such a PJM request is considered an emergency action and is implemented prior to a voltage reduction. LM derives a demand resource or interruptible-load-for-reliability credit in RPM.

Reliability Criteria

PJM's RTEP process rigorously applies NERC's Planning Standard TPL-001-4 through a wide range of reliability analyses – including load and generation deliverability tests – over a 15-year planning horizon. PJM documents all instances where the system does not meet applicable reliability standards and develops system reinforcements to ensure compliance. NERC penalties for violation of a standard can be as high as \$1 million per violation, per day.

PJM addresses transmission expansion planning from a regional perspective, spanning transmission owner zonal boundaries and state boundaries to address the comprehensive impact of many system enhancement drivers, including NERC reliability criteria violations. Reliability criteria violations may occur locally, in a given transmission owner zone, driven by an issue in that same zone. Violations may also be driven by some combination of regional factors.

Bulk Electric System Facilities

NERC's planning standards apply to all bulk electric system (BES) facilities, defined by ReliabilityFirst Corporation and the SERC Reliability Corporation to include all of the following power system elements:

1. Individual generation resources larger than 20 MVA or a generation plant with aggregate capacity greater than 75 MVA that is connected via step-up transformer(s) to facilities operated at voltages of 100 kV or higher
2. Lines operated at voltages of 100 kV or higher
3. Associated auxiliary and protection and control system equipment that could automatically trip a BES facility, independent of the protection and control equipment's voltage level (assuming correct operation of the equipment)

The ReliabilityFirst definition of BES excludes the following:

1. Radial facilities connected to load-serving facilities or individual generation resources smaller than 20 MVA or a generation plant with aggregate capacity less than 75 MVA where the failure of the radial facilities will not adversely affect the reliable steady-state operation of other facilities operated at voltages of 100 kV or higher
2. The balance of generating plant control and operation functions (other than protection systems that directly control the unit itself and its associated step-up transformer), which facilities would include relays and systems that automatically trip a unit for boiler, turbine, environmental and/or other plant restrictions
3. All other facilities operated at voltages below 100 kV

Given this BES definition, PJM conducts reliability analyses to ensure system compliance with NERC Standard TPL-001-4. If PJM identifies violations, it develops transmission expansion solutions to resolve them, frequently as part of its RTEP window process.

NERC Reliability Standard TPL-001-4

Under NERC Reliability Standard TPL-001-4, “planning events” – as NERC refers to them – are categorized as P0 through P7 and defined in the context of system contingency:

- P0 – No Contingency
- P1 – Single Contingency
- P2 – Single Contingency (bus section)
- P3 – Multiple Contingency
- P4 – Multiple Contingency (fault plus stuck breaker)
- P5 – Multiple Contingency (fault plus relay failure to operate)
- P6 – Multiple Contingency (two overlapping singles)
- P7 – Multiple Contingency (common structure)

PJM studies each event as part of one or more steady-state analyses, described in PJM Manual 14B, PJM Region Transmission Planning Process⁷ and summarized shown in **Table 1**. Consistent with NERC definitions, if an event comprises an equipment fault such that the physical design of connections or breaker arrangements also takes additional facilities out of service, then they are taken out of service as well. For example, if a transformer is tapped off a line without a breaker, both the line and transformer are removed from service as a single contingency event.

PJM N-0 analysis – shown in **Table 1** as a NERC planning event, is mapped to planning event P0 – examines the bulk electric system as-is, with all facilities in service. PJM identifies facilities that have pre-contingency loadings that exceed applicable normal thermal ratings. Bus voltages are also identified that violate established limits specified in PJM Manual 3: Transmission Operations.⁸

PJM N-1 analysis – mapped to planning event P1 – requires that BES facilities be tested for the loss of a single generator, transmission line or transformer. Likewise, bus voltages that exceed limits specified by PJM Manual 3 are also identified. Generator and load deliverability tests are also applied to event P1.

PJM N-1-1 analysis – mapped to planning events P3 and P6 – examines the impact of two successive N-1 events with re-dispatch and system adjustment prior to the second event. Monitored facilities must remain within normal thermal and voltage limits after the first N-1 contingency and re-dispatch and within applicable emergency thermal ratings and voltage limits after the second as specified in PJM Manual 3.

⁷ PJM Manual 14B, PJM Region Transmission Planning Process: <https://www.pjm.com/-/media/documents/manuals/m14b.ashx>

⁸ PJM Manual 3, Transmission Operations: <https://www.pjm.com/-/media/documents/manuals/m03.ashx>

PJM N-2 analysis – mapped to planning events P2, P4, P5 and P7 – encompasses multiple contingency and common mode analyses to evaluate the loss of multiple facilities that share a common element or system protection arrangement. These include bus faults, breaker failures, double-circuit tower line outages and stuck breaker events. N-2 analysis is conducted on the base case itself. Common mode analysis itself is conducted within the context of PJM's deliverability testing methods, discussed in PJM Manual 14B.

NERC Standard TPL-001-4 includes extreme events as well. PJM studies system conditions following a number of extreme events, also known as maximum credible disturbances, judged to be critical from an operational perspective for risk and consequences to the system.

Stability Requirements

PJM conducts stability studies to ensure that the planned system can withstand NERC criteria disturbances and maintain stable operation throughout PJM's planning horizon. NERC criteria disturbances are those required by the NERC planning criteria applicable to system normal, single-element outage and common mode multiple-element outage conditions. A key aspect of NERC Reliability Standard TPL-001-4 also calls for modeling the dynamic behavior of loads as part of stability analysis at peak load levels. Prior to TPL-001-4 standard implementation, stability analyses were conducted on static load models that may not necessarily have captured the dynamic nature of real and reactive components of system loads and energy efficient loads, for example. From an analytical perspective, this requirement enhances analysis of fault-induced delayed voltage recovery or changes in load characteristics like that of more energy efficient loads.

PJM performs multiple tiers of analysis to ensure system stability in compliance with NERC Standard TPL-001-4 based on system contingencies of reasonable probability. Those contingencies comprise disturbances applicable to system-normal, single element outage and common-mode multiple-element outage conditions. Following a disturbance, any observed system oscillations must display sufficient positive damping.

- *PJM System-Wide Analysis* – System stability assessment at peak load is performed on one-third of the network each year so that the entire system is analyzed every three years. In addition, the analysis also includes an evaluation under light load conditions, typically the most challenging from a stability perspective.
- *Interconnection Request System Impact Studies* – Generating unit stability analysis is performed by PJM as a part of the System Impact Study for proposed generation interconnection to the PJM system. The analysis identifies any potential stability concerns between the new generator and existing bulk electric system facilities.
- *Operational Performance Issues* – Stability assessments are also conducted on an as-needed basis when system topology changes occur or are proposed in areas with known, limited stability margins. These assessments are frequently driven by system conditions and events arising out of actual operations.

PJM's stability study process is described in Attachment G of Manual 14B.

Table 1. Mapping PJM RTEP Analysis to NERC Planning Events

| Steady-State Analysis | NERC Planning Events |
|-----------------------------------------------|----------------------|
| Base Case N-0 – No Contingency Analysis | P0 |
| Base Case N-1 – Single Contingency Analysis | P1 |
| Base Case N-2 – Multiple Contingency Analysis | P2, P4, P5, P7 |
| N-1-1 Analysis | P3, P6 |
| Generator Deliverability | P0, P1 |
| Common Mode Outage Procedure | P2, P4, P5, P7 |
| Load Deliverability | P0, P1 |
| Light Load Reliability Criteria | P1, P2, P4, P5, P7 |

Baseline Reliability Analysis

Baseline reliability analyses assess base case thermal and voltage conditions in the context of RTEP process load deliverability and generation deliverability test conditions, N-1-1 contingencies, common mode contingencies, light load criteria, winter criteria, as well as short circuit duty and system stability studies. Contingency analyses examine all PJM bulk electric facilities (BES), lower-voltage facilities monitored by PJM and critical facilities in systems adjoining PJM, including tie lines. All reliability analyses are conducted to ensure compliance with NERC Reliability Standard TPL-001-4.

PJM tests for compliance with all reliability criteria imposed by the NERC reliability standards. These standards require PJM to identify the system conditions that sufficiently stress the transmission system and evaluate them to ensure that it meets the thermal and voltage performance criteria specified in the standards.⁹ PJM establishes the critical system conditions through the application of its load deliverability and generator deliverability test procedures.

⁹ RTEP process reactive analysis discussed within the context of Interconnection Reliability Operating Limits (IROLs) transfer interface development as described in **Appendix C**.

Load Deliverability

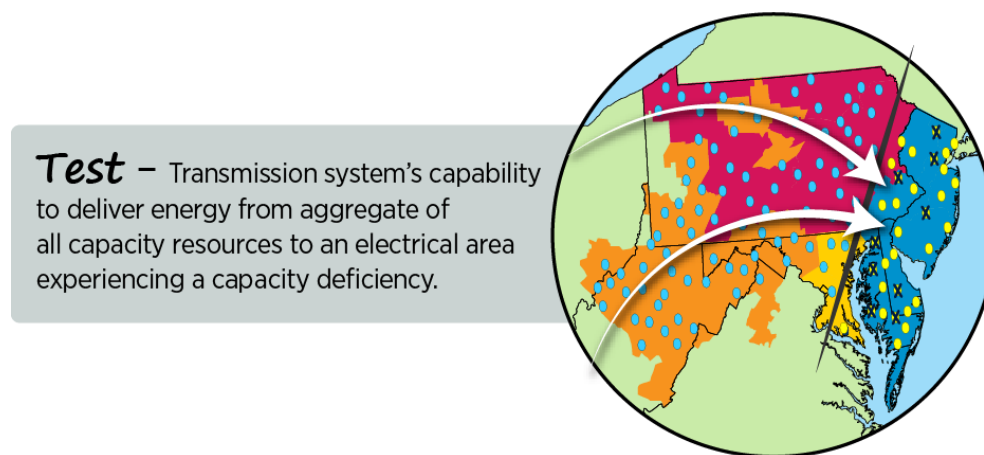
PJM's load deliverability test ensures that load inside a load deliverability area experiencing a capacity deficiency can be served by generating resources external to it, shown conceptually in **Figure 3**. More specifically, load deliverability studies test the transmission system's capability to import sufficient power to meet a defined capacity emergency transfer objective (CETO). The CETO is the import capability required for each of 27 locational deliverability areas¹⁰ to meet a risk level that a defined area would need to shed load due solely to its inability to import needed capacity assistance during a capacity emergency.

PJM calculates a CETO value for each locational deliverability area using a probabilistic model of the load and capacity located within each locational deliverability area. The model recognizes, among other factors, historical load variability, load forecast error, generating unit maintenance requirements and generating unit forced outage rates.

Load deliverability power flow analysis results identify the capacity emergency transfer limit (CETL) for each locational deliverability area. This value represents the maximum megawatts that a locational deliverability area can import under specified peak load test conditions. Transmission system topology changes, load forecasts, generation additions and generation deactivations can all impact CETL values. Each locational deliverability area is tested for its expected import capability up to established transmission facility limits, indicating how much an area can actually be expected to import, CETL. If the CETL value is less than CETO, the test fails, indicating the need for additional transmission capability. Transmission limits are defined in terms of facility thermal ratings and voltage limits.

A locational deliverability area fails the test if sufficient generating capacity cannot be delivered to load because of one or more limiting transmission constraints. The methodology requires that PJM stress the locational deliverability area being tested by (1) increasing its load from a 50/50 forecast level to a 90/10 level and (2) increasing the level of unavailable generation higher than typically encountered. Testing methods are described in more detail in PJM Manual 14B.

Figure 3. Load Deliverability Concept



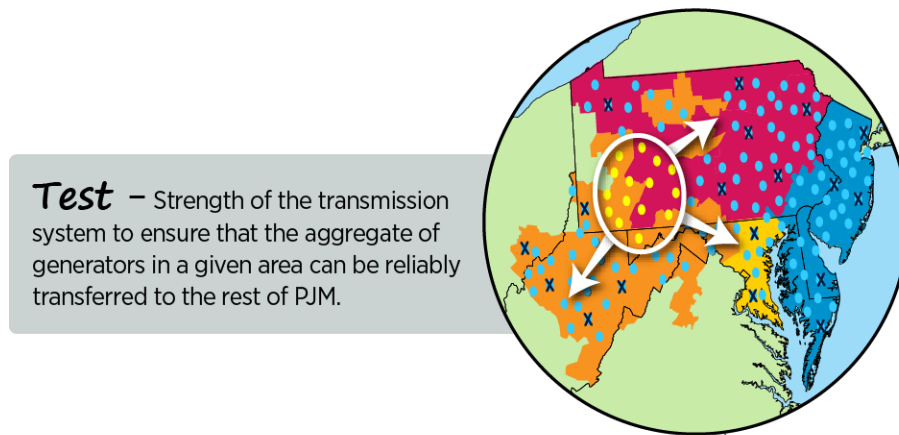
¹⁰ Load deliverability areas are defined in **Appendix B**.

Generator Deliverability

The generator deliverability test ensures sufficient transmission capability exists to deliver generating capacity reliably from a defined area to the rest of PJM load, as shown in **Figure 4**. Test areas are defined based on the potential ramping impact of generators that are electrically close to a particular flowgate. PJM conducts this power-flow test under summer and winter peak load conditions when capacity is most needed to serve load, as well as under light load conditions to ensure that a range of resource combinations and conditions are examined.

Generator deliverability testing assesses single contingencies as part of baseline analysis and interconnection request studies. Testing methods are described in more detail in PJM Manual 14B. In addition, common mode analysis evaluates planning events P2, P4, P5 and P7 to look at the loss of multiple facilities in the context of generator deliverability test conditions, also as described in Manual 14B.

Figure 4. Generator Deliverability Concept



N-1-1 Analysis

N-1-1 contingency studies examine the impact of two successive N-1 events with system adjustments prior to the second event, as shown in **Figure 5**. PJM identifies facilities that have post-contingency flows that exceed applicable emergency ratings and that exceed normal ratings after system adjustment. Voltages are also monitored for compliance with existing voltage limits specified by PJM operations in Manual 3. RTEP enhancements are developed to resolve criteria violations where the applicable rating after the first contingency or the applicable rating after the second contingency are exceeded.

Figure 5. PJM Baseline Reliability N-1-1 Analysis



Light Load Analysis

Light load system conditions within PJM have been observed as low as 30 percent of summer peak in some transmission owner zones. PJM system operators have encountered thermal overloads and high voltage events driven by low demand generation dispatch patterns and the capacitive effects of lightly loaded transmission lines.

Generation dispatch differs markedly from that under peak load conditions, particularly for units powered by intermittent, renewable sources like wind. RTEP-process light load analysis ensures the transmission system is capable of delivering generating capacity during light load periods.

PJM's modifies its peak load baseline power flow base case – as shown in **Table 2** – to reflect light load demand levels, interchange and generation dispatch. System analysis is conducted at a load level reflecting 50 percent of the 50/50 summer peak demand forecast, representative of reasonably stressed light load conditions. PJM zonal interchange levels reflect statistical averages typical of those in prior years during light load periods. Likewise, interchange with external systems is based on historical statistical averages. As **Table 2** shows, planning studies consider capacity factor by type of generator, including wind-powered facilities.

PJM's generator deliverability test does not guarantee that a specific resource will be able to deliver energy under light load conditions. Rather, the purpose is to demonstrate that generators that typically run during light load periods in a given area can run simultaneously. The test also demonstrates that excess power above an area's demand can be exported to the rest of PJM without causing reliability criteria violations.

Table 2. Light Load Analysis Assumptions

| Light Load Analysis Elements | Initial Study Assumptions |
|-----------------------------------------------------------------------------------------------------------------------------|--------------------------------------------------------------------------------------------------------------|
| Network Model | 5-year-out base case |
| Load Model | Light load level at 50% of a non-diversified forecasted 50/50 summer peak load, reduced by energy efficiency |
| PJM Base Generation Resource Capacity Factors (Modeled Online in Base Case Dispatch; Percent of Summer Max Megawatt) | Nuclear at 100% |
| | Coal >= 500 MW at 60% |
| | Coal < 500 MW at 45% |
| | Oil at 0% |
| | Natural gas at 0% |
| | Wind at 40% |
| | All other resources at 0% |
| MISO Base Generation Resource Capacity Factors (Modeled Online in Base Case Dispatch) | Pumped storage at full pump |
| | Wind at 100% |
| Interchange Values | Historical statistical averages during off-peak load periods. |
| Contingencies | NERC categories P0 – P7 (except N-1-1) |
| Monitored Facilities | BES (Base Analysis) and all PJM market monitored facilities (Generator Deliverability) |

Winter Criteria

Winter peak reliability analysis tests the ability of an electrical area to export generation resources to the remainder of PJM during winter peak conditions. PJM models generation based on a historical mix of generation types and output levels typically observed during winter peak conditions. The analysis ensures that generation capability, including wind facilities that typically operate at winter peak, as well as pumped hydro, can be delivered to the rest of PJM.

Table 3 summarizes winter peak base modeling parameters. The method to determine potential overloads is similar to the methods used for the generator deliverability test described earlier. Also, the common mode outage analysis is conducted to evaluate the impacts of NERC P2, P4, P5 and P7 planning events: bus faults, faulted breakers and double-circuit tower line outages. Winter criteria analysis also tests gas pipeline contingencies. PJM's gas pipeline contingency set includes those caused by failure of a gas pipeline or a compressor station. The contingency set is reviewed and validated periodically to ensure accurate analysis.

Table 3. Winter Peak Base Case Modeling Parameters

| Network Model | Current year + five base case | |
|---------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------|----------------|
| Load Model | 50/50 Winter Peak with the bus by bus load profile set by the local transmission owner | |
| Capacity Factor for Base Generation Dispatch for PJM Resources (Online in Base Case) | Fuel Type | Percent |
| | Solar | 5 |
| | Wind | 33 |
| | Water | 38 |
| | Nuclear | 98 |
| | Coal < 500 MW | 51 |
| | Coal >= 500 MW | 73 |
| | Landfill Gas | 46 |
| | Natural Gas | 25 |
| | Other Biomass Gas | 111 |
| | Oil (Distillate Fuel) | 1 |
| | Oil (Black Liquor) | 74 |
| | Oil (Kerosene) | 0 |
| | Oil (Residual Fuel) | 2 |
| | Municipal Solid Waste | 79 |
| | Wood Waste | 66 |
| | Waste Coal | 75 |
| Petroleum Coke | 75 | |
| Other Solid | 19 | |
| Interchange Values | Yearly Long-Term Firm Transmission Service (except MAAC, which will use historical averages) | |
| Contingencies | NERC Category P0, P1, P2, P3, P4, P5, P6 and P7 | |
| Monitored Facilities | BES (N-1-1, Base Analysis) and all PJM market monitored facilities (Generator Deliverability) | |

Short Circuit Studies

PJM conducts short circuit analysis to ensure compliance with NERC Reliability Standard TPL-001-4. The standard requires that each bulk electric system circuit breaker have adequate fault interrupting capability. Simulated single-phase-to-ground and three-phase fault currents are compared to the breaker interrupting capabilities provided by transmission owners. All simulated fault currents greater than breaker ratings are identified and necessary enhancements developed, often requiring replacement of the breaker itself to implement a higher current interrupting rating. Short circuit analysis is performed consistent with the following industry standards:

- ANSI/IEEE 551-2006 – Governs the recommended practice for calculating short circuit currents in industrial and commercial power systems, how circuit breaker short circuit current information is provided and how related power system equipment is used to sense and interrupt fault currents.
- ANSI/IEEE C37.04-1999 – Governs the rating structure for AC high-voltage circuit breakers and associated equipment.
- ANSI/IEEE C37.010-1999 – Governs AC high voltage circuit breakers rated on a symmetrical current basis, taking into consideration reclosing duration, reactance to resistance ratio differences, temperature conditions, etc.
- ANSI/IEEE C37.5-1979 – Governs fault current calculation of AC high-voltage breakers that are rated on a total current basis.

Each of these standards is applied together with transmission owners' methodologies as a basis to calculate fault currents on all bulk electric system breakers. All breakers whose calculated fault currents exceed breaker interrupting capabilities are considered overdutied and reported to transmission owners for confirmation.

PJM develops two-year-out and five-year-out short circuit cases. The two-year planning case consists of the current system together with all RTEP system enhancements planned to be in service within the next two years. The five-year planning case uses the two-year-out planning case as modified to include all system enhancements, generating resources and merchant transmission projects planned to be in service within five years, consistent with the five-year PJM RTEP power flow base case. Additional detail can be found in Section G.7 of Attachment G, PJM Manual 14B.

Generation Deactivation Analysis

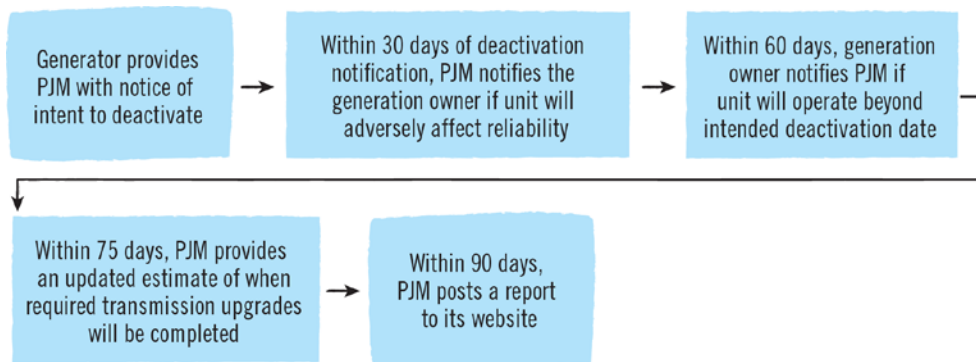
Generation owners are required to notify PJM of their intent to deactivate generation per Article V of the PJM tariff. Per FERC order, PJM cannot compel unit owners to remain in service. Unlike timelines associated with requests for interconnection, deactivation may take effect upon 90 days' notice,¹¹ as shown in **Figure 6**. After deactivation notification is received, PJM conducts a series of studies to determine if the generator removal will have an adverse impact on BES reliability in light of established criteria and standards. Generator deactivations alter power flows that often yield transmission line overloads and, given reductions in system reactive support from those generators, can undermine voltage support.

¹¹ PJM maintains a list of generator deactivation notifications as formally submitted by asset owners:
<http://pjm.com/planning/generation-deactivation.aspx>.

If reliability criteria violations are identified, baseline transmission enhancements are developed to resolve those violations. The scope of deactivation reliability studies comprises thermal and voltage analysis under generator deliverability, common mode outage, N-1-1 and load deliverability tests. System expansion solutions may include enhancements to existing facilities, scope expansion for current baseline projects already in the RTEP or the construction of altogether new facilities. Transmission enhancements required to maintain a reliable system are identified and reviewed with the subregional RTEP committees and the Transmission Expansion Advisory Committee (TEAC). The cost of transmission enhancements to mitigate criteria violations caused by generation deactivation is allocated to load.

If transmission improvements are completed prior to a unit's intended deactivation date, reliability issues can be avoided. However, if improvements are not in place prior to deactivation, and if reasonable operating procedures cannot be implemented, then PJM can pursue a reliability must-run (RMR) agreement with the generator owner. Doing so can keep a unit online beyond its announced retirement date until transmission improvements are completed. Under the PJM Open Access Transmission Tariff, costs incurred to compensate RMR generator owners are recovered through an additional transmission charge allocated to transmission owners' zonal load that bears the financial responsibility for the required transmission improvements. Regardless, a generation owner is not under any obligation to pursue the RMR agreement and may retire the unit at any time. PJM cannot compel a generator to remain in service.

Figure 6. Generator Deactivation Process



Transmission Relay Loadability

The purpose of NERC Reliability Standard PRC-023-3 is to ensure protective relay settings do not limit transmission loadability, do not interfere with system operators' ability to take remedial action to protect system reliability and are set so that they reliably detect all fault conditions. The standard specifies how protective relays should be set to prevent potential cascade tripping that could occur when protective relay settings limit transmission loadability. The objective of the standard is to identify the facilities that must meet those requirements. Accordingly, a number of transmission system elements are subject to the requirements of Standard PRC-023-3.

PJM conducts an assessment at least once each calendar year, with no more than 15 months between assessments. Doing so can identify those facilities for which transmission owners, generator owners, and distribution providers must comply. Additional information can be found in PJM Manual 14B, Attachment G, Section 10.

Transmission Owner Criteria

The PJM Operating Agreement specifies that individual transmission owner (TO) planning criteria¹² are to be evaluated as a part of the RTEP process, in addition to NERC and PJM regional criteria. Frequently, TO planning criteria address specific local system conditions, such as in urban areas. TOs are required to include their individual criteria as part of their respective FERC Form No. 715 filings. As part of its RTEP process, PJM applies TO criteria to the respective facilities that are included in the PJM Open Access Transmission Tariff (OATT) facility list. While transmission enhancements driven by TO criteria are considered RTEP baseline projects, they are assigned to the incumbent TO and are not eligible for proposal window consideration. Under the terms of the OATT, the costs of such projects are allocated 100 percent to the TO zone.

PJM has observed that TO aging infrastructure criteria are increasingly driving the need for baseline projects. Review of facilities built in the 1960s and earlier have revealed deteriorating facilities. Planning for aging infrastructure is not new to PJM. Spare 500/230 kV transformers, aging 500 kV line rebuilds and other equipment enhancements approved in prior years are already part of the RTEP. In other instances, TO criteria encompass local loss-of-load thresholds, particularly on radial facilities. The threshold for some is on a megawatt-mile basis, others on a megawatt-magnitude basis to reduce the extent of load impacted.

Operational Performance

Under Schedule 6, Section 1.5 of the PJM Operating Agreement, PJM may also identify transmission enhancements to address system limitations encountered during real-time operations, often under recurring similar system conditions. To that end, PJM planners meet with operations staff several times each year to assess the need for transmission enhancement plans that would address identified thermal, reactive, stability and other issues. This has been the case, for example, over the past several years under light load conditions during which operators experienced high voltage alarms. Additional studies replicating operating conditions have revealed that reactors were needed in certain areas to resolve the issue.

¹² TO criteria can be found on the PJM website: <https://www.pjm.com/planning/planning-criteria/to-planning-criteria.aspx>.

Market Efficiency

The RTEP process also examines market efficiency to identify baseline transmission enhancements that relieve congested facilities, allowing lower cost power to flow to consumers. PJM's market efficiency analysis encompasses the following objectives:

- Identify new transmission enhancements that may realize economic benefit
- Determine which reliability-based enhancements have economic benefit if accelerated
- Review the reliability-based enhancements already included in the RTEP that, if modified, would relieve one or more congestion constraints, providing additional economic benefit

In other words, in the second two instances, projects originally identified to resolve reliability criteria violations may be designed in a more robust manner to provide economic benefit as well.

Congestion

Congestion occurs when the least costly resources that are available to serve load in a given region cannot be dispatched because transmission facility limits constrain power flow on the system. This is particularly true in PJM, where power often flows from lower-priced generating resources in western zones to load centers in the east. The lowest-priced energy is often constrained from flowing freely to those load centers. When this occurs, PJM's system operator must dispatch higher cost resources to serve load. This causes LMP differences and congestion on the system. The congestion generally increases system production costs, LMPs, and results in increased customer payments for electric energy.

Benefit/Cost Threshold Test

PJM calculates a benefit/cost ratio to determine if there is a market efficiency justification for a particular transmission enhancement. The benefit/cost ratio is calculated by comparing the net present value of annual benefits over the first 15 years of the project's life to the net present value of the project's revenue requirement for the same period. Market efficiency proposed transmission enhancements that meet or exceed a 1.25 benefit/cost ratio are further assessed to examine their economic, system reliability and constructability impacts.

The purpose of a benefit/cost ratio threshold is to hedge against the uncertainty of estimating benefits in the future and to provide a degree of assurance that a project with a 15-year net-benefit near zero will not be approved. At the same time, the threshold is not so restrictive as to unreasonably limit the economic-based enhancements or expansions that would be eligible for inclusion in the RTEP. Detailed descriptions of the benefit/cost ratio metric and associated analytical methodologies used to determine economic benefit are described in PJM Manual 14B¹³ and PJM Operating Agreement.¹⁴

¹³ PJM Manual 14B, Section 2.6: <https://www.pjm.com/-/media/documents/manuals/m14b.ashx>.

¹⁴ PJM Operating Agreement, Schedule 6, Section 1.5.7: <https://www.pjm.com/library/governing-documents.aspx>.

In order to determine and evaluate the potential economic benefit of RTEP projects, PJM performs market simulations and calculates a benefit-to-cost ratio for each candidate project. Doing so requires that the net present value of annual benefits be calculated for the first 15 years of project life and compared to the net present value of the project revenue requirement for the same 15-year period. A discount rate and levelized carrying charge rate is developed using information contained in transmission owner formula rate sheets (Attachment H).¹⁵

PJM's Operating Agreement also requires that proposed transmission enhancements with a total cost exceeding \$50 million undergo an independent third-party cost review. This is intended to ensure consistent estimating practices and project-scope development. For the majority of proposed transmission enhancements, PJM determines market efficiency benefits based on Energy Market simulations. Proposed transmission enhancements that may impact PJM Reliability Pricing Model (capacity market) auction activities may derive additional economic benefit as determined through capacity market simulations.

To assure that projects selected by the PJM Board for market efficiency continue to be economically beneficial, both the costs and benefits of these projects will be reviewed periodically (nominally on an annual basis). Substantive changes in the costs and/or benefits of the approved RTEP projects will be reviewed with the TEAC to determine if these projects continue to provide economic benefits relative to their costs and should remain in the RTEP.

Determining Economic Benefit

PJM identifies the economic benefit of proposed transmission enhancements by conducting production cost simulations. These simulations show the extent to which congestion is mitigated by a transmission enhancement for specific study-year transmission and generation dispatch scenarios. Economic benefit is determined by comparing future-year simulations both with and without the proposed transmission enhancement.

To conduct an Energy Market benefit analysis, PJM uses a market simulation tool to model hourly security-constrained generation commitment and economic dispatch over a future annual period. A detailed generation, load and transmission system model is used as input into the simulation tool in order to mimic the hourly commitment and dispatch of generation to meet load, while recognizing constraints imposed on the economic commitment and dispatch of generation by the physical limitations of the transmission system.

PJM also licenses a commercially available production cost database containing the necessary data elements to perform detailed PJM market simulations. This database is periodically updated providing an up-to-date representation of the Eastern Interconnection and in particular PJM markets. The PJM Transmission Expansion Advisory Committee (TEAC) reviews the key analysis input parameters: fuel costs, emissions costs, load forecasts, demand resource projections, generation projections, expected future transmission topology and several financial valuation assumptions.

¹⁵ Transmission owner formula rate sheets (Attachment H): <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates.aspx>.

The primary difference among cases is the corresponding transmission topology:

- An “as-is” base case power flow models a one-year-out study year transmission topology
- An “as-planned” base case power flow models PJM Board-approved RTEP projects with a required in-service date of June 1 of a five-year-out study year
- Project analysis includes the topology for the specific transmission enhancement under study

PJM determines transmission enhancement economic value by comparing the results of multiple simulations with the same input assumptions and operating constraints but different transmission topologies. Importantly, the simulated transmission congestion results also provide important system information and trends to potential transmission developers and other PJM stakeholders.

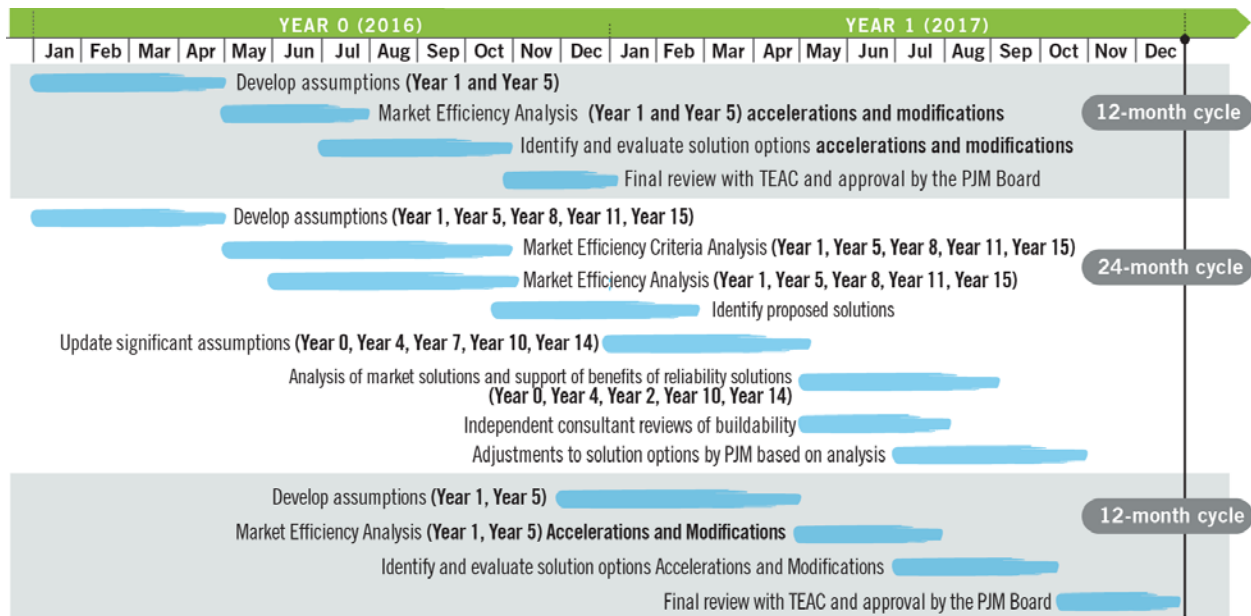
Near-Term Simulations: One Year and Five Years Out

PJM uses near-term simulations to assess the individual and collective economic impact of RTEP enhancements not yet in service, shown in **Figure 7**. PJM quantifies the transmission congestion reduction due to recently planned RTEP enhancements by comparing the simulation differences between the “as-is” base case and the “as-planned” base case for the study years. Simulation comparisons allow PJM to quantify the transmission congestion reduction due to the collection of recently planned RTEP enhancements. The comparisons can also reveal if specific already-planned transmission enhancements may eliminate or relieve congestion so that the constraint is no longer an economic concern and identify if a reliability-based enhancement may provide economic benefits that would make it a candidate for acceleration or modification. If a candidate for acceleration, the enhancement cost is considered against the benefit of accelerating a reliability-based project before any recommendation is made to the PJM Board.

Long-Term Market Efficiency Need

In order to quantify future longer-range transmission system market efficiency needs, PJM develops simulation study cases for study years one, five, eight and 11 years out, as also shown in **Figure 7**. The congestion results from this set of analyses are publicly posted as prelude to opening of a long-term proposal window. PJM solicits proposals to address identified market efficiency issues at the end of the first year of a 24-month cycle. During the second year, the market efficiency models are updated with the latest assumptions and window-submitted proposals are evaluated using those updated models. This provides a mechanism in place for regularly identifying transmission system enhancements to relieve future congestion.

Figure 7. PJM RTEP Process Market Efficiency 24-Month Study Cycle



Energy Benefit – Regional Facilities

The energy benefit calculation for regional facilities¹⁶ is weighted as follows:

- 50 percent to change in system production cost
- 50 percent to change in net load energy payments for zones with a decrease in net load payments as a result of the proposed transmission enhancement

The change in system production cost is the change in system generation variable costs (i.e., fuel costs, variable operating and maintenance costs, emissions costs) associated with total PJM energy production. The change in net-load energy payment is the change in gross-load payment offset by the change in transmission rights credits. The net-load energy payment benefit is calculated only for zones in which the proposed project decreases the net load payments. Zones for which the net load payments increase because of the proposed transmission enhancement are excluded from the net-load energy payment benefit.

¹⁶ Regional Facilities are defined to mean transmission enhancements or expansions that, among other things, will operate at or above 500 kV or will be double-circuit 345 kV facilities, per PJM's Open Access Transmission Tariff, Schedule 12, section (b)(i).

Energy Benefit – Lower Voltage Facilities

The energy benefit calculation for lower voltage facilities is weighted 100 percent to zones with a decrease in net load payments as a result of the proposed transmission enhancement. The change in net load energy payment is the change in gross load payment offset by the change in transmission rights credits. The net load payment benefit is only calculated for zones in which the proposed transmission enhancement decreases the net load payments. Zones for which the net load payments increase because of the proposed transmission enhancement are excluded from the net load energy payment benefit.

Capacity Benefit – Regional Facilities

PJM's annual capacity benefit calculation for regional facilities is weighted as follows:

- 50 percent to change in total system capacity cost
- 50 percent to change in net load capacity payments for zones with a decrease in net load capacity payments as a result of the proposed transmission enhancement

The change in net load capacity payment is the change in gross capacity payment offset by the change in capacity transfer rights.

Capacity Benefit – Lower Voltage Facilities

PJM's annual capacity benefit calculation for lower voltage facilities is weighted 100 percent to zones with a decrease in net load capacity payments as a result of the proposed transmission enhancement. The change in net load capacity payment is the change in gross capacity payment offset by the change in capacity transfer rights.

Putting Benefits in Context

In order to understand simulation results in proper context, PJM leverages PROMOD's sophisticated modeling to define a hierarchy of areas for calculating production cost benefit, as shown in **Figure 8**. Within PJM, this fundamentally starts with the Transmission Owner (TO) zone for the purposes of establishing asset ownership and cost allocation. TO zones generally correspond to those that have forecasted load in PJM's annual Load Forecast report. These zones are also gathered within sequentially larger RTO sub-regions. PJM notes that a separate area is defined to capture the impacts of external unit long-term firm import reservations in the model. Additionally, merchant transmission owners that use part of the PJM transmission system can be allocated costs of new transmission and captured as part of a separate PROMOD function.

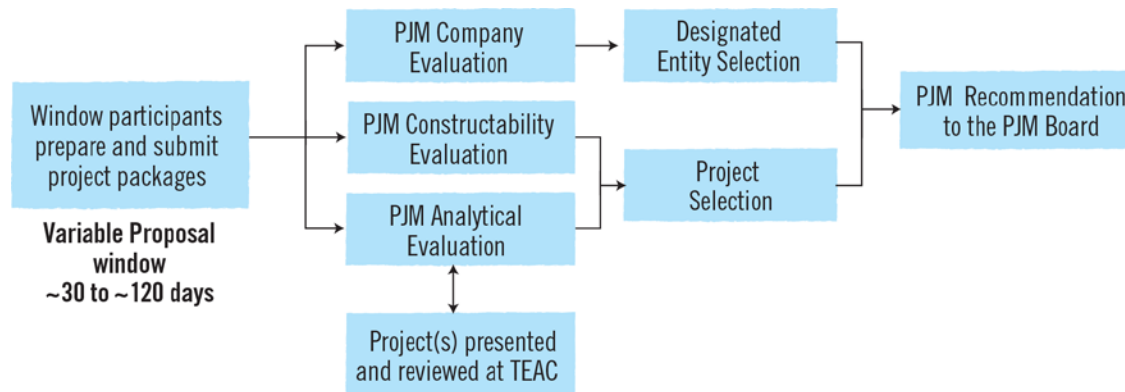
Figure 8. PJM Energy Market Simulation Area Definitions

| LEVEL 1 | LEVEL 2 | LEVEL 3 | LEVEL 4 | LEVEL 5 | ENTITY TYPE | |
|---------------------------|--------------------------|-----------------------------|-------------------------------|---------------------------------------|-----------------------------|---------|
| PJM Interconnection | PJM Mid-Atlantic | PJM Mid-Atlantic East | | Atlantic Electric | TO Zone | |
| | | | | Delmana Power & Light Company | TO Zone | |
| | | | | Jersey Central Power & Light Company | TO Zone | |
| | | | | PECO Energy Company | TO Zone | |
| | | | | Public Service Electric & Gas Company | TO Zone | |
| | | | | Rockland Electric Company | TO Zone | |
| | | | Sub-Region | | | |
| | | PJM Mid-Atlantic South West | | Baltimore Gas & Electric Company | TO Zone | |
| | | | | Potomac Electric Power Company | TO Zone | |
| | | | Sub-Region | | | |
| | | PJM Mid-Atlantic West | PJM Mid-Atlantic East PA | | Metropolitan Edison Company | TO Zone |
| | | | | | PPL Electric Utilities | TO Zone |
| | PJM Mid-Atlantic West PA | | | Sub-Region | | |
| | | | Pennsylvania Electric Company | TO Zone | | |
| | PJM West | | | Allegheny Power | TO Zone | |
| | | | | American Electric Power | TO Zone | |
| | | | | Commonwealth Edison Company | TO Zone | |
| | | | | Dayton Power & Light Company | TO Zone | |
| Duke Energy Ohio/Kentucky | | | | TO Zone | | |
| Duquesne Light Company | | | | TO Zone | | |
| East Kentucky Power Coop. | | | | TO Zone | | |
| FirstEnergy ATSI | | | | TO Zone | | |
| PJM South | | | Virginia Power Company | TO Zone | | |
| | | | | | | |
| | PJM Firm Reservations | | | LT Firm Use | | |

RTEP Process Windows

PJM seeks transmission proposals during each RTEP window to address one or more identified needs – reliability, market efficiency, operational performance and public policy. RTEP windows provide opportunity for non-incumbent transmission developers to submit project proposals to PJM for consideration. The scope and timing of the issue to be addressed and likely type of solutions to be submitted dictate window duration. Once a window closes, PJM proceeds with specific company, analytical and constructability evaluations to assess proposals for possible recommendation to the PJM Board as shown in **Figure 9**. If selected, designated developers become responsible for project construction, ownership, operation, maintenance and financing.

Figure 9. RTEP Proposal Window Process



The expected type of system enhancement and required in-service data dictates window duration:

- Long-Lead Projects:** PJM will open a 120-day proposal window for projects with required in-service dates greater than five years out that address identified reliability criteria violations, economic constraints, RPM limitations and public policy requirements. Please note that the 120-day proposal window is a default. PJM may shorten or extend the window as needed.
- Short-Term Projects:** PJM will open a 30-day proposal window for projects to address reliability driven projects with required in-service dates between three and five years out. Please note that the 30-day proposal window is a default. PJM may shorten or extend the window as needed.
- Immediate-Need Reliability Projects:** A reliability-based transmission enhancement or expansion with a required in-service date of three years or less. If PJM determines that insufficient time remains to develop and implement a short-term project by way of a proposal window, PJM will work directly with the impacted transmission owner to develop and implement solutions. If PJM determines that sufficient time remains, PJM will conduct a RTEP proposal window seeking solutions to address the immediate need project. PJM has the direction to dictate the length of the required proposal window based on the complexity of the issue.

During each window, developers may submit solution proposals to solve posted violations, constraints, system conditions and public policy requirements. PJM may then also request any additional reports or information needed to evaluate the specific project proposal. Any deficiencies must be addressed within 10 business days of notification from PJM. PJM may also: (i) shorten proposal windows should it be required to meet the needed in-service date of the proposed enhancements or expansions; or (ii) extend the windows as needed to accommodate updated information regarding system conditions.

Submittals include both greenfield and upgrade proposals. A greenfield proposal is one that utilizes new right-of-way or creates a new substation, for example. An upgrade proposal is an enhancement or expansion to existing transmission system facilities. Upgrades can include new or replaced devices installed at existing substations and reconductoring or other modifications of existing transmission lines.

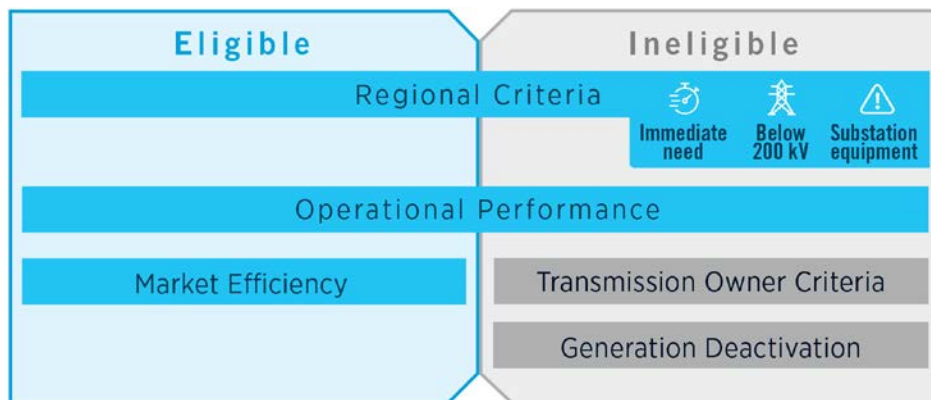
Window Eligibility

Figure 10 shows window eligibility for specific transmission enhancement drivers. After PJM identifies potential violations and needs based on the analyses performed under the criteria tests described in PJM Manual 14B, PJM initiates a review process to determine if each flowgate is appropriate for inclusion in a RTEP proposal window. By default, all identified PJM market monitored reliability criteria violations are assumed to be included in an RTEP Proposal window unless they fall into one of the following exemption categories:

- Immediate-need regional reliability projects
- Transmission Owner-filed FERC Form 715 Local Planning Criteria¹⁷
- Lower Voltage (<200 kV) Facilities
- Transmission Substation Equipment

Baseline transmission enhancements needed to solve reliability criteria violations driven by generation deactivation are not eligible for window consideration given the inherently short timeframe required for project completion. Window eligibility for operational performance-driven need is based on timeframe and nature of the expected solution – greenfield or upgrade. The long-term horizon of transmission needs driven by market efficiency studies permits them to be eligible for RTEP window consideration.

Figure 10. PJM RTEP Window Eligibility



Company Evaluation

PJM evaluates a company's specific ability to construct, own, operate, maintain and finance the specific project it has proposed. Prior to window activity, entities that desire to participate in the proposal window process, and perhaps ultimately be assigned as a project's designated entity, must submit a pre-qualification package to PJM during a separately specified period of time. Companies are evaluated based on their overall ability to engineer, develop, construct, operate and maintain a transmission facility within PJM. If a company does not have experience in a specific area, PJM requires that it provide a detailed plan for leveraging the experience of affiliates and contractors.

¹⁷ FERC Form 715 Local Planning Criteria: <https://www.pjm.com/planning/planning-criteria/to-planning-criteria.aspx>.

Constructability Evaluation

Constructability evaluation assesses proposals in terms of cost, schedule, siting, permitting, right-of-way, land acquisition, project complexity and coordination risks. Project completion schedules and cost estimates are influenced by a number of factors: for example, line routing, siting and permitting, environmental remediation, engineering, material procurement, line construction, expansion of existing substations, project management and contingencies. Greenfield projects typically need to acquire land and rights-of-way. PJM may engage in discussions with federal, state and local regulatory agencies to understand the scope of specific permitting issues.

Analytical Evaluation

Analytical evaluation assesses proposals in terms of performance with respect to the specific, identified needs:

- Reliability analyses evaluate transient stability, voltage, thermal and short circuit performance, per established NERC reliability planning criteria.
- Market efficiency analyses evaluate a proposed project's ability to relieve transmission congestion consistent with established benefit-to-cost metrics.
- Public policy analyses evaluate a proposal's performance with respect to its ability to satisfy public policy objectives and requirements, such as the delivery of renewable energy to customer load within a given state.

Following completion of these evaluations and review with stakeholders via TEAC, PJM submits its recommendation to the PJM Board for consideration.

RTEP Project Approval and Next Steps

PJM staff recommend projects to the PJM Board that represent solutions that satisfy technical performance requirements and balance advantages and risks with regard to cost commitment, constructability and other factors. Once the PJM Board approves recommended projects – new facilities (greenfield) and upgrades to existing ones – they formally become part of PJM's overall RTEP. The PJM Board approval obligates each Designated Entity with the responsibility for the construction, ownership, maintenance, and operation of certain transmission components, under the terms and conditions of an executed two-party Designated Entity Agreement.

Frequently, PJM management and subject matter experts are asked by a Designated Entity to become witnesses with respect to project need justification as part of a specific state jurisdiction proceeding for facility approval. That approval typically comprises a Certificate of Public Convenience and Necessity (CPCN).

New Service Queue Requests

The five-year dimension of PJM's Regional Transmission Expansion Plan (RTEP) process permits PJM to assess and recommend transmission enhancements not only to meet forecasted near-term load growth but also to ensure reliability in light of new customer requests for the following:

- Generation interconnection
- Merchant network enhancements
- Incremental auction revenue rights
- Merchant transmission interconnection
- Long-term firm transmission service

PJM conducts two new service queue windows per year according to the PJM Open Access Transmission Tariff for PJM to accept new service requests. Each window is open for six months; the first queue window closes on March 31 of the calendar year. The second closes on September 30 of the same calendar year. A new service request will be assigned a queue position only when all tariff-required information, data, agreements and deposits are submitted. PJM then conducts deliverability and other tests to identify and resolve any NERC, regional and transmission owner reliability criteria violations.

Generation Interconnection Requests

Generator interconnection requests constitute a significant driver of regional transmission expansion needs. Feasibility, system impact and facilities studies ensure that new resources interconnect without violating established NERC criteria. Interconnection requests for generation powered by renewable fuel sources require specific analytical studies unique to their particular characteristics. For example, wind-powered generator requests have clustered in remote areas most suitable to their operating characteristics and economics but with less robust transmission infrastructure. Such an injection of power increases system stress in areas already limited by existing operating restrictions. Consequently, PJM is increasingly encountering the need for complex power-system stability studies and low-voltage ride-through analysis.

PJM's queue-based new service request process offers developers the flexibility to pursue capacity, energy, ancillary service, and other business opportunities in PJM. While a developer can withdraw at any point, the process is structured such that each step imposes its own increasing financial obligations on the developer. As part of queue studies, PJM conducts the necessary deliverability and other tests to identify any NERC, regional and transmission owner reliability criteria violations to be resolved. PJM's Open Access Transmission Tariff, Section VI governs the terms and conditions under which parties seek new service. PJM Manuals 14A and 14B describe related business rules and test methodologies.

A key component of PJM's RTEP process is the assessment of queued interconnection requests and the development of transmission plans to resolve reliability criteria violations identified under prescribed deliverability tests. Generation interconnection requests may be evaluated as a PJM capacity resource or as an energy-only resource, or a combination of both, based on what the developer has requested. Completion of identified transmission plans permits capacity interconnection rights (CIRs) to be assigned to a generator in order to participate in PJM's Reliability Pricing Model capacity market. CIRs ensure capacity resource adequacy in Reliability Pricing

Model auctions, based on the unit output PJM can expect from a resource over peak summer hours. Subsequently, PJM's annual RTEP cycle encompasses studies that assess transmission expansion plans needed to ensure the ongoing deliverability of all generators within PJM consistent with their CIRs.

Each developer's interconnection request specifies whether its generation is to be evaluated as a PJM capacity resource, an energy-only resource, or a combination of both. Capacity resource status allows a generator to participate in PJM's RPM-based capacity market or as a fixed revenue resource. Under the terms of PJM's Reliability Assurance Agreement,¹⁸ in order to qualify as a capacity resource, sufficient transmission capability must exist to ensure that generator output is deliverable to PJM's aggregate network load under peak load conditions at the requested point of interconnection. From an RTEP process perspective, PJM conducts deliverability and common mode outage studies as part of compliance with NERC and regional reliability criteria. Studies may identify system enhancement for a unit to interconnect to the PJM grid reliably and receive its requested capacity rights. The developer bears the cost responsibility for the reinforcements necessary to resolve identified reliability criteria violations. Subsequent annual RTEP cycles encompass studies to ensure the ongoing deliverability of all generators within PJM, consistent with their capacity interconnection rights. Energy-only resource units are only permitted to participate in the energy market. Such units do not receive capacity interconnection rights and may not participate in PJM capacity markets. The planning studies for generating units seeking energy resource status do not include the deliverability analyses required of those units seeking capacity resource status.

Merchant Transmission Interconnection Requests

Merchant transmission facilities are AC or DC transmission facilities that are interconnected with or added to the transmission system in accordance with the PJM Open Access Transmission Tariff. These facilities are not existing facilities of the transmission system, transmission facilities included in the rate base of a public utility on which a regulated return is earned, transmission facilities included in previous RTEPs or customer interconnection facilities.

When developers of merchant transmission facilities interconnect such facilities to the PJM transmission system, they may be entitled to elect certain transmission rights, subject to restrictions. Much like the generation interconnection requests, those for merchant transmission follow a queue-based series of feasibility, system impact and facilities studies to ensure that such facilities interconnect without violating established NERC criteria.

Merchant Network Projects

A developer can also request additions to, or modifications or replacements of, existing transmission owner transmission facilities or existing RTEP system enhancements. This can include accelerating the construction of transmission enhancements, other than Merchant Transmission Facilities, that are already included in PJM's RTEP. Once the request is received, PJM conducts a system impact study and coordinates the development of estimated costs.

¹⁸ The Reliability Assurance Agreement (RAA) among load-serving entities in the region PJM serves is intended to ensure that adequate capacity resources will be planned and made available to provide reliable service to loads within PJM, to assist other parties during emergencies and to coordinate planning of capacity resources consistent with the reliability principles and standards: <https://www.pjm.com/directory/merged-tariffs/raa.pdf>.

Long-Term Firm Transmission Service Requests

PJM's fundamental responsibility is to plan and operate a safe and reliable transmission system that serves all long-term firm transmission uses on a comparable and not unduly discriminatory basis. This responsibility is addressed by PJM RTEP reliability planning studies that ensure reliability under the most stringent applicable NERC, PJM or local transmission owner criteria. Indeed, an important, ongoing aspect of this responsibility is the consideration of specific Long-Term Firm Transmission Service requests (LTFTS) for point-to-point and integrated network transmission service for a period of a year or more. Point-to-point transmission can be used for the transmission of capacity and/or energy into, out of, through, or within PJM. Firm transmission service is reserved and/or scheduled between specified points-of-receipt and delivery.

Network transmission service allows network customers to utilize their network resources to serve their network load located within PJM. Once all required PJM OASIS steps have been completed, and transmission service agreements have been executed, the evaluation process can begin. Each request for transmission service is evaluated by PJM to determine if sufficient capability exists to ensure reliable service to all transmission customers. PJM evaluates each LTFTS request using the same deliverability tests employed for generation interconnection requests, consistent with the NERC, ReliabilityFirst Corporation and SERC reliability criteria for installation of generation and transmission. Deliverability studies can identify criteria violations driving the need for transmission enhancements to ensure system reliability. Once identified transmission system requirements are in place, the transmission service request can be awarded.

Auction Revenue Rights

PJM's RTEP process includes analysis of Stage 1A Auction Revenue Rights (ARRs) over a 10-year period to ensure simultaneous feasibility. PJM conducts DC power flow N-1 analysis to ensure that all subscribed ARR transmission entitlements are within the capability of PJM's existing transmission system. Requests for ARRs must specify a source, sink and megawatt amount. If a violation occurs in any of 10 years, PJM develops an RTEP solution.

ARRs are the mechanism by which the proceeds from the Annual Financial Transmission Rights Auction (FTR) are allocated.¹⁹ ARRs entitle the holder to receive an allocation of the revenues from the Annual FTR Auction. The PJM Operating Agreement, Section 7.8, Schedule 1 sets forth provisions permitting any party to request incremental ARRs by agreeing to fund transmission improvements necessary to support the requested financial rights.

Interregional Planning

PJM currently has interregional planning arrangements with New York Independent System Operator (NYISO), the Independent System Operator of New England (ISO-NE), Midcontinent Independent System Operator (MISO), North Carolina Transmission Planning Collaborative, Duke Energy, Tennessee Valley Authority (TVA), and Southeastern Regional Transmission Planning (SERTP), shown on **Map 2**. Interregional planning with the Carolinas and TVA are conducted under SERTP processes embodied in the Tariff provisions of PJM and the SERTP sponsors subject to

¹⁹ PJM Manual 6, Financial Transmission Rights: <http://www.pjm.com/~media/documents/manuals/m06.ashx>.

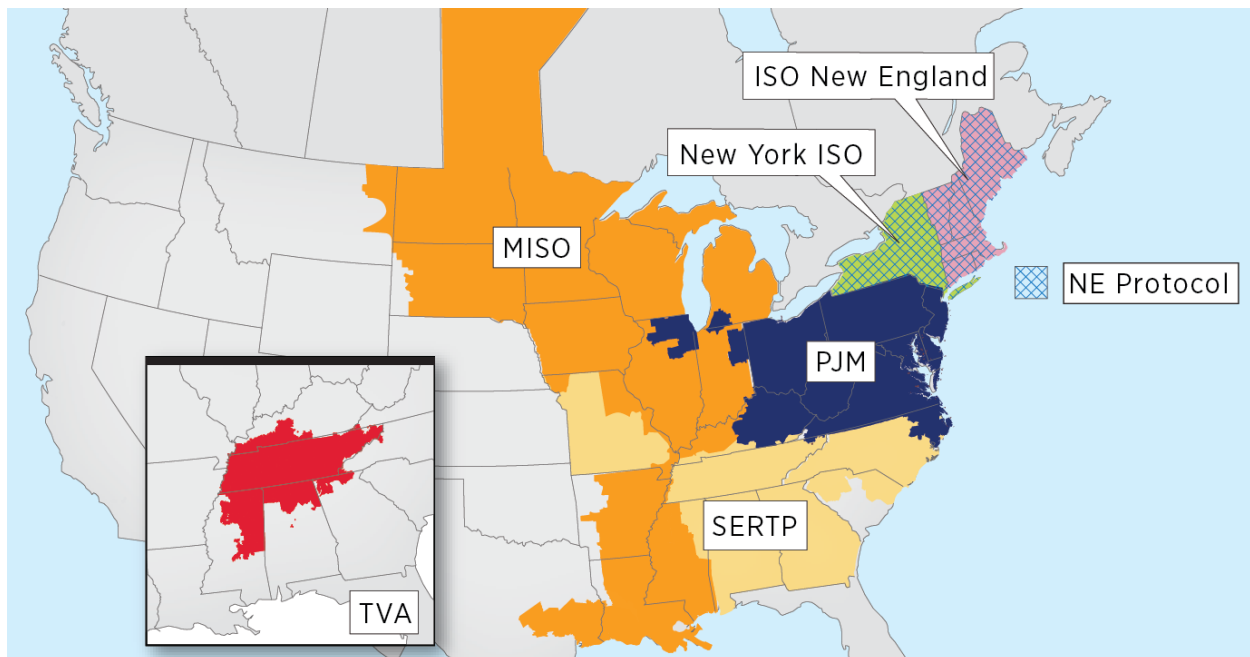
FERC jurisdiction. SERTP sponsors include Duke Energy Progress (jurisdictional), TVA, Southern Company (jurisdictional), Georgia Transmission Corporation, Municipal Electric Authority of Georgia, PowerSouth, Louisville Gas and Electric and Kentucky Utilities (jurisdictional), Associated Electric Cooperative, Ohio Valley Electric Cooperative (jurisdictional) and Dalton Utilities. PJM also actively participates in ongoing activities of the Eastern Interconnection Planning Collaborative (EIPC).

Under each interregional agreement, provisions governing coordinated planning include assessment of current and potential future operational issues to ensure that critical cross-border interface issues are identified and addressed before they impact system reliability or dilute effective market administration. The planning processes applicable to each of PJM's three interfaces include provisions to address system impacts of mutual concern:

- Individual regional transmission plans
- Queued generator interconnection requests
- Generator deactivation requests
- Operational performance
- National and state public policy objectives
- Power flow modeling accuracy within regional planning processes

Studies are conducted in accordance with a specifically defined scope and may include cross-border analyses that examine reliability, market efficiency or public policy needs. Reliability studies may examine transfers, stability, short circuit, generation and merchant transmission interconnections and generator deactivations.

Map 2. PJM Interregional Planning



Stakeholder Forums

PJM's open and transparent encompasses a number of on-line and in-person stakeholder forums for Regional Transmission Expansion Planning (RTEP) process discussion and collaboration.

Planning Community

PJM's online communities create an easily accessible venue for stakeholders to collaborate with PJM staff and each other. The Planning Community allows stakeholders to collaborate and find information on planning initiatives, proposal windows and processes. It includes similar features to the Member Community, along with access to PJM subject matter experts and moderated discussions between generation owners, transmission owners and PJM staff. The Planning Community can be accessed online: <https://pjm.force.com/planning/sl/>.

Stakeholder Committee Forums

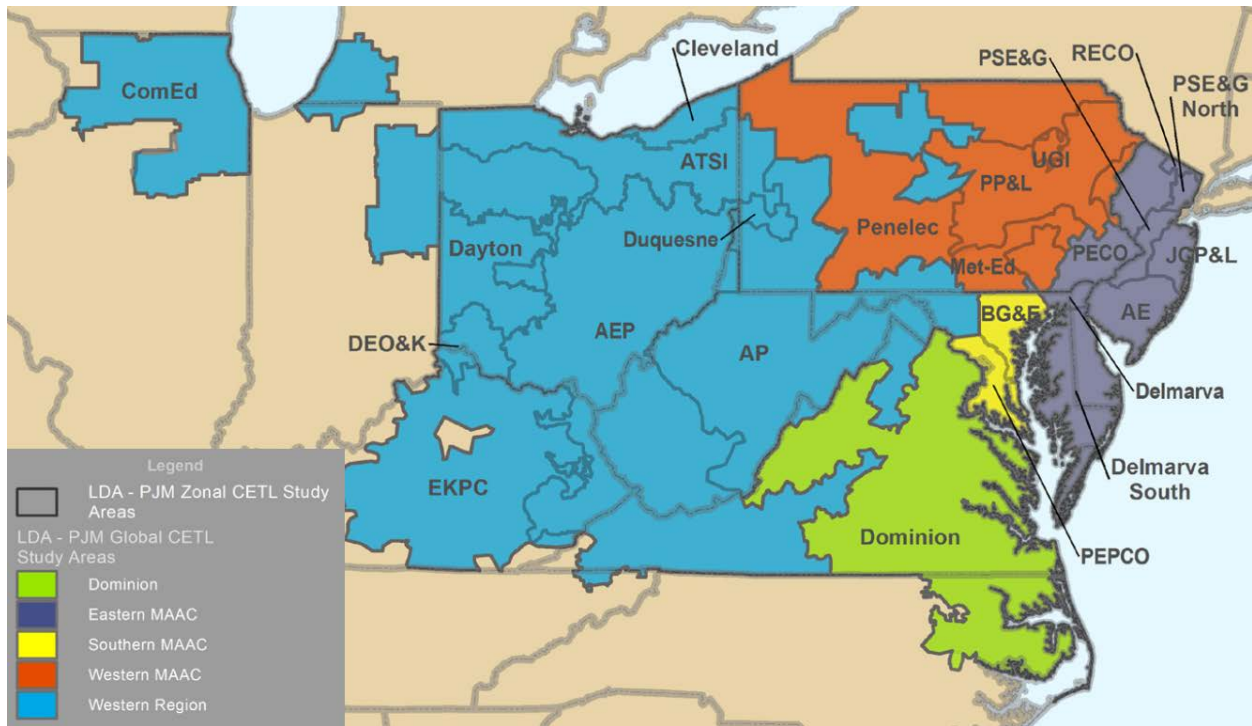
The Planning Committee, established under the PJM Operating Agreement, has the responsibility to review and recommend system planning strategies and policies as well as planning and engineering designs for the PJM bulk power supply system to assure the continued ability of the member companies to operate reliably and economically in a competitive market environment. Additionally, the Planning Committee makes recommendations regarding generating capacity reserve requirement and demand side valuation factors. Committee meeting materials and other resources are available on the PJM website: <https://www.pjm.com/committees-and-groups/committees/pc.aspx>.

The *Transmission Expansion Advisory Committee (TEAC)* and *subregional RTEP committees* continue to provide forums for PJM staff and stakeholders to exchange ideas, discuss study input assumptions and review results. Stakeholders are encouraged to participate in these ongoing committee activities:

- TEAC resources are available on the PJM website: <https://www.pjm.com/committees-and-groups/committees/teac.aspx>.
- Each subregional RTEP committee provides a forum for stakeholders to discuss local planning concerns. Interested stakeholders can access subregional RTEP committee planning process information from the PJM website:
 - PJM Mid-Atlantic Subregional RTEP Committee: <https://www.pjm.com/committeesand-groups/committees/srtepm-a.aspx>
 - PJM Western Subregional RTEP Committee: <https://www.pjm.com/committees-andgroups/committees/srtepm-w.aspx>
 - PJM Southern Subregional RTEP Committee: <https://www.pjm.com/committees-andgroups/committees/srtepm-s.aspx>

The *Independent State Agencies Committee (ISAC)* is a voluntary, stand-alone committee comprising representatives from regulatory and other agencies in state jurisdictions within the PJM footprint. Through the activities of the ISAC, states have an opportunity to provide input on the assumptions and scenarios that PJM incorporates in the scope of its RTEP studies. Additional information is available on the PJM website: <https://www.pjm.com/committees-and-groups/isac.aspx>.

Appendix B: PJM Locational Deliverability Area Definitions



| Entity Name | Description |
|-----------------------|-----------------------------------------------------------------------------------|
| AE | Atlantic Electric |
| AEP | American Electric Power |
| APS | Allegheny Power |
| ATSI | American Transmission Systems, Incorporated |
| BGE | Baltimore Gas and Electric |
| Cleveland | Cleveland Area |
| ComEd | Commonwealth Edison |
| DAYTON | Dayton Power and Light |
| DEO&K | Duke Energy Ohio and Kentucky |
| DLCO | Duquesne Light Company |
| Dominion | Dominion Virginia Power |
| DPL | Delmarva Power and Light |
| Delmarva South | Southern Portion of DPL |
| Eastern Mid-Atlantic | Global area – JCP&L, PECO, PSE&G, AE, DPL, RECO |
| EKPC | East Kentucky Power Cooperative |
| JCP&L | Jersey Central Power and Light |
| METED | Metropolitan Edison |
| Mid-Atlantic | Global Area – Penelec, METED, JCP&L, PPL, PECO, PSE&G, BGE, PEPSCO, AE, DPL, RECO |
| PECO | PECO |
| PENELEC | Pennsylvania Electric |
| PEPCO | Potomac Electric Power Company |
| PPL | PPL Electric Utilities Corporation, UGI |
| PSE&G | Public Service Electric and Gas |
| PSE&G North | Northern Portion of PSE&G |
| Southern Mid-Atlantic | Global area – BGE and PEPSCO |
| Western Mid-Atlantic | Global Area – Penelec, METED, PPL |
| Western PJM | Global Area – APS, AEP, Dayton, DUQ, ComEd, ATSI, DEO&K, EKPC, OVEC |

Appendix C: IROL Transfer Interface Limit Development

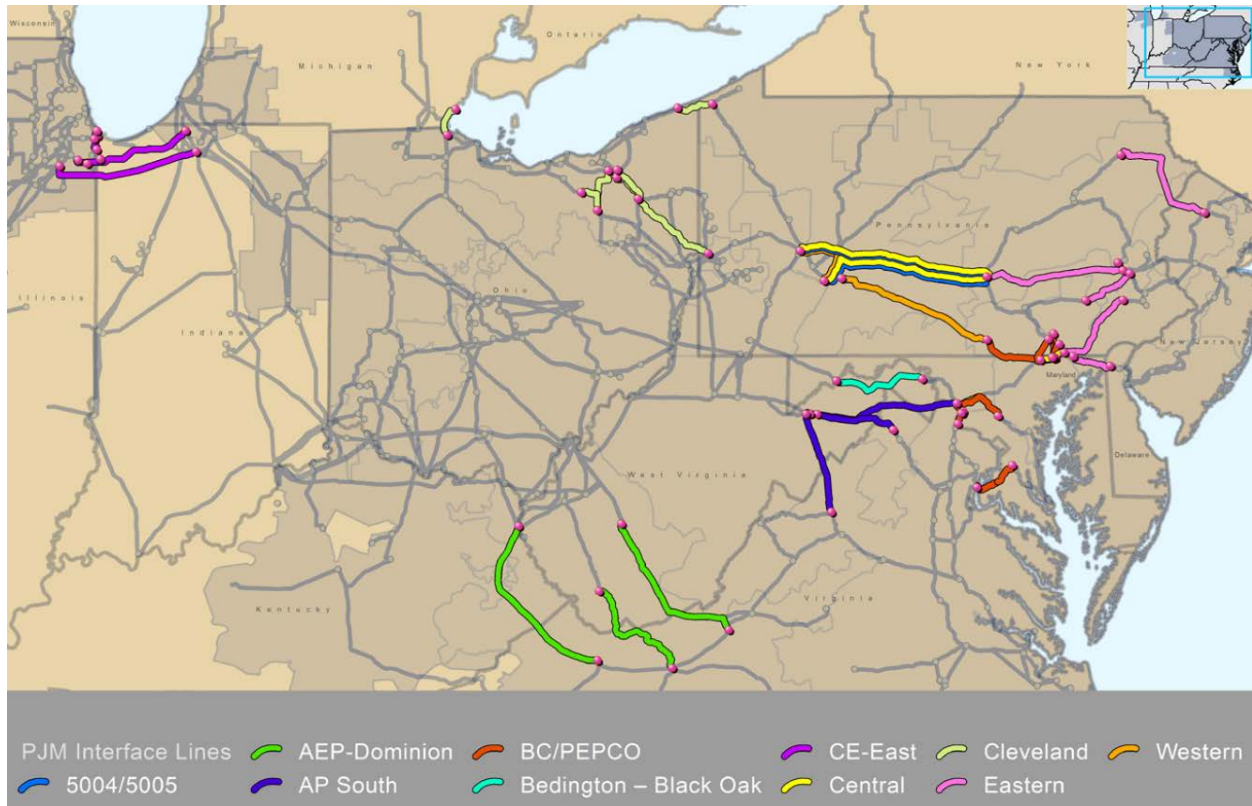
PJM system operators must ensure that power flow levels do not exceed each of eight established Interconnection Reliability Operating Limits (IROLs). Such limits, if violated, "...could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Bulk Electric System," as defined by NERC.

Each IROL comprises a set of transmission facilities that together define an interface. The sum of the IROL's flows must remain below a limit defined by operational study so that voltage stability is maintained in real time. In short, for a transfer level above a defined IROL, voltage collapse across the region could occur. PJM monitors IROLs and flows in real-time and studies them in day-ahead simulations to ensure voltage stability is maintained. In PJM, IROLs are defined primarily in terms of 10 reactive transfer interfaces as shown in **Table 4** and **Map 3**.

Table 4. PJM Transfer Interface Definitions

| Transfer Interface | Interface Definition (From Bus to Bus) | |
|--------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| Eastern (Eastern) | <ul style="list-style-type: none"> • 5059 Breinigsville – Albury #1 500 kV line • 5058 Breinigsville – Albury #2 500 kV line • 5009 Juniata – Albury 500 kV line • 5066 Lauschtown – Hosensack 500 kV line | <ul style="list-style-type: none"> • 5010 Peach Bottom – Limerick 500 kV line • 5025 Rock Springs – Keeney 500 kV line • 5063 Lackawanna – Hopatcong 500 kV line |
| Central (Central) | <ul style="list-style-type: none"> • 5004 Keystone – Juniata 500 kV line • 5005 Conemaugh – Juniata 500 kV line | <ul style="list-style-type: none"> • 5012 Conastone – Peach Bottom 500 kV line |
| 5004/5005 (5004/5005) | <ul style="list-style-type: none"> • 5004 Keystone – Juniata 500 kV line • 5005 Conemaugh – Juniata 500 kV line | |
| Western (Western) | <ul style="list-style-type: none"> • 5004 Keystone – Juniata 500 kV line • 5005 Conemaugh – Juniata 500 kV line | <ul style="list-style-type: none"> • 5068 Vinco – Hunterstown 500 kV line • 5055 / 522 Doubs – Brighton 500 kV line |
| Bedington – Black Oak (Bed-Bl) | <ul style="list-style-type: none"> • 544 Black Oak – Bedington 500 kV line | |
| AP South (AP South) | <ul style="list-style-type: none"> • 583 Bismark – Doubs 500 kV line • 540 Greenland Gap – Meadow Brook 500 kV line | <ul style="list-style-type: none"> • 550 Mt. Storm – Valley 500 kV line • 529 Mt. Storm – Meadow Brook 500 kV line |
| AEP – Dominion (AEP-DOM) | <ul style="list-style-type: none"> • Kanawha River – Matt Funk 345 kV line • Wyoming – Jacksons Ferry 765 kV line | <ul style="list-style-type: none"> • Baker – Broadford 765 kV line |
| Cleveland (CLVLND) | <ul style="list-style-type: none"> • Hanna – Chamberlin 345 kV line • Hanna – Juniper 345 kV line • Star – Juniper 345 kV line • Star – North Medina 345 kV line | <ul style="list-style-type: none"> • Erie West – Ashtabula 345 kV line • Mansfield – Glenwillow 345 kV line • Monroe – Lallendorf 345 kV line |
| CE-East (CE-EAST) | <ul style="list-style-type: none"> • Dumont – Wilton Center 765 kV line • Olive – University Park North 345 kV line • St. Johns – Crete 345 kV line | <ul style="list-style-type: none"> • Sheffield - Burnham 345 kV line • Sheffield - Stateline 345 kV line • Munster - Burnham 345 kV line |
| BC/PEPCO (BC/PEPCO) | <ul style="list-style-type: none"> • 5055/522 Doubs – Brighton 500 kV line • 5013 Hunterstown – Conastone 500 kV line • 5012 Peach Bottom – Conastone 500 kV line • 560/5070 Possum Point – Burches Hill 500 kV line • Aqueduct - Dickerson 230 kV line • Doubs – Dickerson 23102 230 kV line | <ul style="list-style-type: none"> • Cooper – Graceton 230 kV line • Edwards Ferry – Dickerson 230 kV line • Otter Creek – Conastone 230 kV line • Safe Harbor - Graceton 230 kV line • Face Rock – Five Forks #1 115 kV line • Face Rock – Five Forks #2 115 kV line |

Map 3. PJM Interconnection Reliability Operating Limits



Calculating Reactive Interface Limits

NERC Reliability Standards require that a transmission system remain stable, within applicable equipment thermal ratings and substation voltage limits.²⁰ PJM rigorously applies NERC operating and planning standards through the application of a wide range of reliability analyses.

As more power is transferred across a line or set of lines, voltage levels decline. The more abrupt the decline in voltage level for each incremental increase in power transfers, the more difficult voltage is to control in real time. Such abrupt decline is typically caused by a system contingency, for example, the sudden and unplanned loss of a generating unit, transmission line or transformer. Transfers are simulated by increasing the load at the Sink (Control Area(s) or subset of Control Area) with the corresponding generation increase at the Source (typically west of the facility/interface being studied) until a voltage violation/collapse is reached. For each incremental increase in transfers, a set of contingencies is applied to determine that which most limits additional pre-contingency transfers as

²⁰ From a PJM RTEP process perspective this encompasses assessment of voltage response under Reliability Standard TPL-001-4 planning events P0 through P7 planning events for deliverability base case analysis and N-1-1 tests. Those tests ensure that the transmission system is able to deliver energy to a portion of the system that is experiencing a capacity deficiency. If voltage level or voltage drop magnitude following the loss of a bulk electric system element violates specified limits, then system enhancements must be developed to resolve the violation.

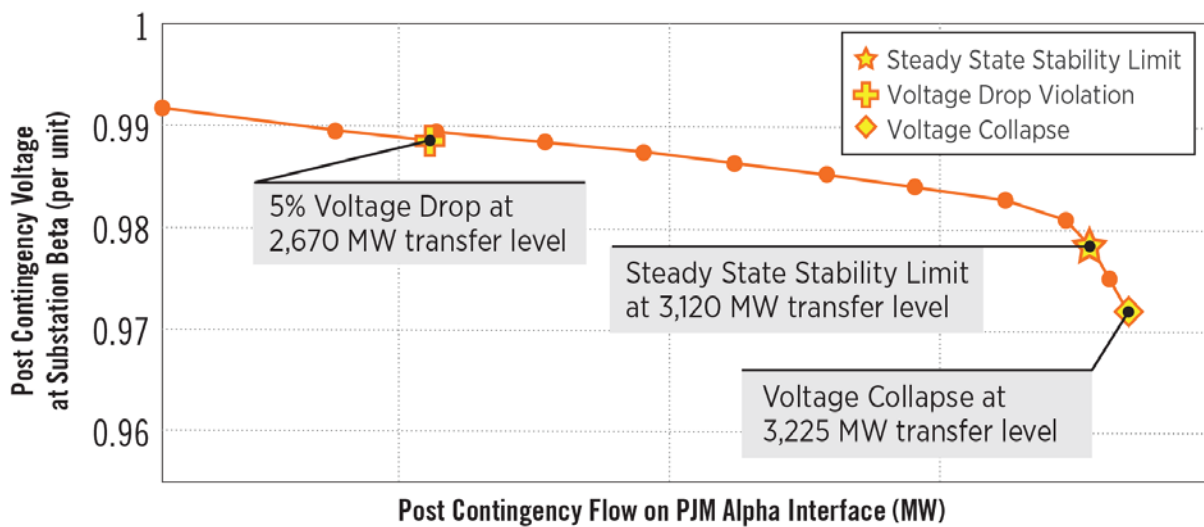
constrained by associated post-contingency voltage drop. Permissible voltage magnitudes and voltage drop percentages are determined based on operational conditions at each substation. Voltage drop is limited at many 500 kV substations to five percent; emergency voltage magnitude is limited to no lower than 0.97 per unit, i.e. 97 percentage of nominal. Voltage magnitude and voltage drop limits are defined in PJM Manual 3, Transmission Operations: <https://www.pjm.com/~media/documents/manuals/m03.ashx>.

Power-Voltage Curves

Voltage collapse occurs when a power system can no longer maintain voltage at a defined bus. As transmission line loading increases, current also increases, which causes a squared increase in the reactive power absorbed by the line. Power-voltage curve analysis provides a rigorous examination of voltage collapse phenomena. Power-voltage analysis allows engineers to evaluate critical BES contingencies on system voltages as power transfers are increased. Substation voltage levels are represented on a curve and can show when reliability criteria violations occur and, beyond that, the point at which voltage collapse can eventually occur, an example of which is shown in **Figure 11**. Power-voltage curves of this type show how increasing power flows on a given line can reach a critical point where further increases would cause the transmission system to collapse. PJM develops these power-voltage curves (known also as “voltage drop curves”) for each interface, where power flow is the sum of that flowing across all defined interface facilities.

This critical point is the “steady state stability limit.” In the **Figure 11** example, this limit is very pronounced. A slight increase in power transfer would cause voltages to collapse following the contingency. Such situations leave little margin for system operators to manage the grid. If presented with the situation in real-time operations, system operators would have little time to react and need to take quick, decisive action by shedding load.

Figure 11. Example Power-Voltage Curve



Controlling Interface Power Flow in Real Time

PJM's Energy Management System (EMS) performs automated online full AC security analysis transfer studies to determine transfer limits for the use in real-time operation. Specifically, the EMS Transfer Limit Calculator (TLC) simulates transfers in order to assess voltage collapse conditions for each reactive interface using the most recent State Estimator solution comprises the TLC simulation starting point. The EMS TLC executes every five minutes and automatically recommends updated transfer limits to PJM system operators. From these results, operators can generate reports which provide generator shift factors, phase angle regulator sensitivity factors, and load distribution factors. The information coupled State Estimator solution and unit bid information serves as the input data for PJM market tools. Through the use of PJM market tools, PJM operators have the ability to use cost-effective generation adjustments to control interface constraints on a pre-contingency basis. Voltages are monitored for compliance with existing voltage limits specified in terms of permissible bus voltage level and contingency voltage drop, as specified by PJM operations in Manual 3, accessible from PJM's website:

<https://www.pjm.com/-/media/documents/manuals/m03.ashx>

Appendix D: Scope and Procedure – Economic Benefit of Approved Transmission

Overview

PJM identifies the economic benefit of transmission assets by conducting production cost simulations. These simulations show the extent to which congestion is mitigated by the project for specific study-year transmission and generation dispatch scenarios. Economic benefit is determined by comparing future-year simulations with and without proposed transmission assets.²¹ PJM conducted the case study presented in **Section 5** of the Benefits of the PJM Transmission System paper in the same manner as it conducts FERC-approved RTEP process market-efficiency analysis. Doing so meant that PJM employed a market simulation tool to model hourly security-constrained generation commitment and economic dispatch for which two simulation cases were developed:

1. An RTEP base case with all future Board-approved transmission assets modeled through 2023
2. A sensitivity study case in which future transmission assets and 10 existing major ones were removed

All transmission removed had in-service dates for the study period 2014 and 2023. The 10 existing major transmission assets in service had analytically already yielded significant congestion reduction over a one-year period. Results of the two simulations were compared to determine the economic value of transmission assets in terms of production cost and load payments:

- **Production costs** represent the fuel costs, variable O&M costs, and emission costs of dispatched resources in PJM. Production costs savings represent system level benefits. New transmission can reduce the variable cost of generation supply to the market.
- **Load payments** represent the cost, measured by the locational marginal prices (LMP), for the energy supplied to the consumer. Load payments are directly affected by the quantity of energy and the price.

Tools and Input Assumptions

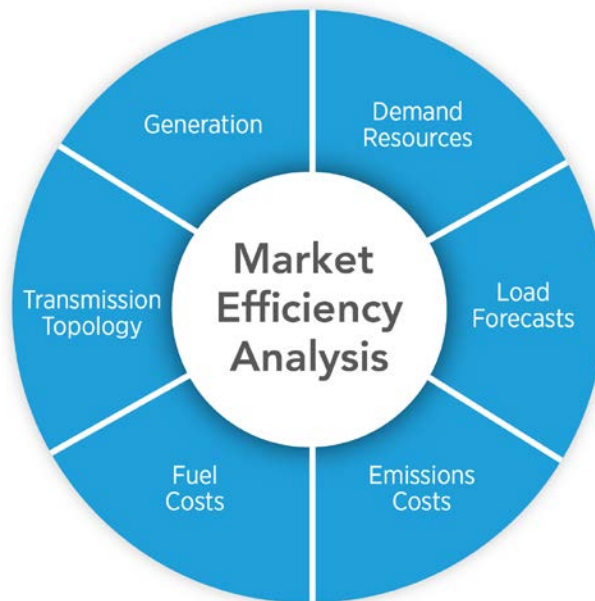
As with its conventional RTEP market efficiency analyses, this case study also used ABB's PROMOD software tool. PROMOD is fundamental electric market simulation software that incorporates extensive, detailed, generating unit operating characteristics, transmission grid topology and constraints, and market system operations. The PROMOD simulation engine employs an hourly chronological dispatch algorithm that minimizes dispatch costs while simultaneously ensuring that defined operating parameters remain within specified constraints: generating unit characteristics, transmission limits, fuel and environmental, considerations, transactions, and customer demand.

²¹ Additional details describing metrics and methods used to determine economic benefit can be found in the following online documentation: PJM Manual 14B, Section 2.6: <https://www.pjm.com/-/media/documents/manuals/m14b.ashx>, and PJM Operating Agreement, Schedule 6, Section 1.5.7: <https://www.pjm.com/directory/merged-tariffs/oa.pdf>.

PJM licenses a commercially available database containing the necessary data elements to perform detailed market simulations. This database is periodically updated to include the most recent representation of the Eastern Interconnection and, in particular, PJM markets. PJM's Transmission Expansion Advisory Committee (TEAC) reviews the key analysis input parameters, shown in **Figure 12**. This data is used to develop forecasted system conditions, consistent with established RTEP process practice. Parameters include fuel costs, emissions costs, load forecasts, demand resource projections, generation projections, expected future transmission topology and financial valuation assumptions.

A detailed generation, load and 2019 study year transmission system model was used as the starting point to simulate hourly generation commitment and dispatch to meet load, while recognizing physical limitations of the transmission system. The simulation data model itself was initially seeded with the latest base release of the PROMOD Simulation Ready Data NERC Database for the Eastern Interconnection. This provided a bus-level, interconnection-wide transmission topology and generation model, which PJM then tailors to its own market efficiency process needs by providing: (1) a more current view of PJM market fundamentals and (2) an updated transmission model for PJM's footprint.

Figure 12. Market Efficiency Analysis Parameters



Generation Parameters

Market-efficiency simulations model existing in-service generation plus actively queued generation with at least an executed facilities study agreement, less planned generator deactivations that have given formal notification. The modeled generation provides enough capacity to meet PJM's installed reserve requirement.

Production cost simulations incorporate the following generation data parameters:

- Identification of capacity and energy resources expected to be in service during the study period
- Retirement of existing resources according to officially announced timetables
- Extension of existing resources in the absence of official retirement announcement
- Addition or modification of future unit-specific resources based on queue processing and load flow representation
- Retirement of database future resources not meeting queue processing requirements
- Scaling of resource capacity to meet planned installed reserve margins, if appropriate

Queued generation includes that which has reached in-service commercial operation, that with signed ISAs/Interim ISAs/or not requiring an ISA, and that with an executed FSA or suspended ISA but expected to become operational during the study period.

Fuel Price Assumptions

PJM uses a vendor provided commercially available database tool that includes generator fuel price forecasts. Forecasts for short-term gas and oil prices are derived from New York Mercantile Exchange future prices. Long-term forecasts for gas and oil are obtained from commercially available databases, as are all coal price forecasts. Vendor-provided basis adders are applied as well to account for commodity transportation cost to each PJM zone.

Load and Energy Forecasts

PJM's 2019 Load Forecast Report provided the transmission zone peak load and energy data modeled in the simulations. Load data used in the market efficiency simulations is a combination of the load shapes embedded in the annual PROMOD database and values representing PJM's official load forecast characteristics. This process includes incorporating the monthly non-coincident peak and energy values by transmission zone as contained in monthly tables released as part of the PJM Load Forecast Report. These data items comprises weather normalized unadjusted peak and energy values and include assumptions for energy efficiency (EE) and distributed solar.

Demand Resources

The amount of demand resources modeled in each transmission zone is based on Table B-7 of the 2019 PJM Load Forecast Report. Production cost simulations model demand resource (DR) products as generation resources. Three resource types are defined for each zone: Limited DR, Extended Summer DR, and Annual DR. DR resources are modeled as discrete resources based on product type, state, transmission zone and historic LMP trends for the load buses where they are modeled.

Emission Allowance Price Assumptions

PJM currently models three major effluents – SO₂, NO_x and CO₂ – within its market efficiency simulations. SO₂ and NO_x emission price forecasts reflect implementation of the Cross-State Air Pollution Rule (CSAPR). CO₂ emissions

are modeled as either part of the national CO₂ program or, for Maryland and Delaware units, as part of the Regional Greenhouse Gas Initiative (RGGI) program.

External Region Modeling

PJM models adjoining external regions, which includes multi-party transactions with commitment and dispatch hurdle rates defined between systems. This allows for economic transactions to flow between control areas within the simulation. PJM's simulation tool also automatically scales generation uniformly to balance the load and losses in inactive external regions to ensure that congestion has not been distorted by parallel flows skewed by original external model development.

Monitored Constraints

Consistent with established practice, PJM's production cost simulation tool monitors specific thermal and reactive interface transmission constraints derived from the following sources:

1. Transmission facilities on PJM's monitored facility list: <https://www.pjm.com/markets-and-operations/transmission-service/transmission-facilities.aspx>.
2. Monitored facilities obtained based on historical analysis of real-time constraints: <https://www.pjm.com/markets-and-operations/energy/real-time.aspx>.
3. Binding non-generator constraints from the previous market year, reviewed and reduced based on constraints that are not practical to model such as those that involve closing normally open breakers, switching load or result in a loss of generation.
4. NERC Book of Flowgates (BOF) constraints to model flowgates jointly controlled by PJM and another region. These are generally external constraints for which PJM generation has a significant Transfer Distribution Factor (TDF).
5. Removal of contingencies that have shown over time that they are not loaded significantly pre- or post-contingency, and thus unlikely to contribute to congestion
6. Constraints that have uncharacteristically high congestion compared to historic congestion results are further analyzed to identify causes. Erroneous congestion can be caused by any number of factors including errors in the load mapping, unrealistic generation maintenance schedules or forced outages, errors in the event modeling, unrealistic loop flow contributions due to static load and static generation modeling, etc.
7. Transmission facilities with historical real-time congestion over the past few years
8. PJM reactive interface limits are modeled as thermal values that correlate to power flows beyond which voltage violations may occur. The modeled interface limits are based on voltage stability analysis and a review of historical values. Modeled values of future-year reactive interface limits incorporate the impact of approved RTEP enhancements on the reactive interfaces.

In production cost simulation runs, reactive transfers are limited through modeling of proxy interfaces composed of transmission lines. The transfers across an interface are the megawatt flows across the transmission paths. The transfer limits are the megawatt transfer beyond which reactive and voltage criteria are violated. These reactive limits are either pre-contingency megawatt limits, or post-contingency megawatt limits. Although these production cost models do not have all the variability observed in operations it is still necessary to limit megawatt flows over these interfaces to ensure a reasonable representation of unit commitment and dispatch in simulation runs.

Determining Benefit

With input assumptions in place, PJM ran two energy market case simulations to compare the economic benefit of transmission assets in terms of production cost and load payment savings. The market simulation tool performed an hourly least-cost, security-constrained commitment and dispatch of generation to meet load over an annual period while recognizing physical limitations of the transmission system and other defined operating constraints: generating unit characteristics, fuel and environmental considerations, transactions, and customer demand. The overall results of the analysis showed that in the PJM Energy Market alone, transmission enhancements approved between 2014 and 2023 would be estimated to reduce costs to customers by more than \$288 million in combined annual load payments and annual production costs. The results showed that transmission enhancements remove system market inefficiencies manifested by persistent congestion to allow greater access to lower cost generation.

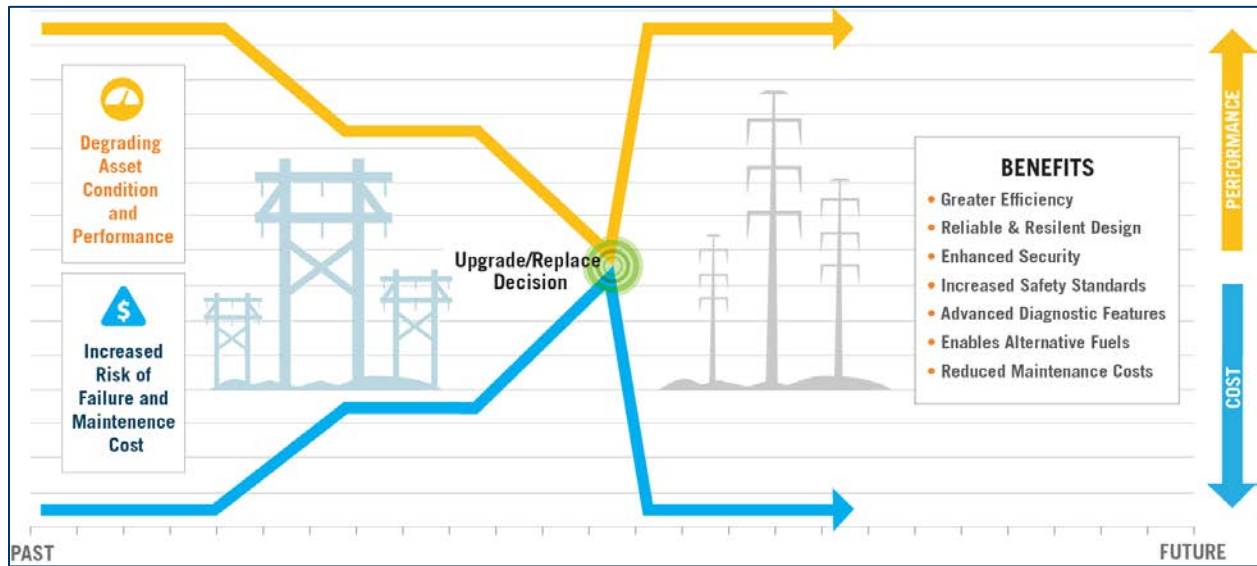
Appendix E: Transmission Owner Asset Management Process

The PJM system is a sophisticated network of numerous assets including 6,650 busses above 100 kV, more than 84,200 miles of transmission at 100 kV and above, to deliver more than 180,000 MW of generation to 65 million people in 13 states and the District of Columbia. Indeed, many call the power grid the largest machine in the world, others call it a plane that never lands. Both descriptions are apt. Each asset encompasses a specific functionality. All must work together for the safe and reliable grid operation. Many of these assets have been in service for a long period of time – some since before 1960 – that employed established engineering principles, design standards, safety codes and good utility practices applicable when they were installed. All have been exposed to varying operating conditions over their respective lives.

The facilities of the PJM transmission grid, while operated by PJM, encompass the physical facilities owned by various transmission owners. While the facilities of transmission owners are operated by PJM as a fully interconnected transmission network, the physical facilities of each individual transmission owner are designed to the particular engineering and construction standards of that owner and maintained by them according to standard utility practices.

Replacement of aging infrastructure is frequently the result of individual transmission owner (TO) asset management assessments. The concept of utility asset management takes its cue from the world of finance, particularly with respect to risk and the predictability of future performance. Fundamentally, asset management is a strategy that seeks to balance performance, cost and risk. A transmission owner's business is asset intensive. The vast majority of investment and spending relates to physical infrastructure. Grid modernization by each TO encompasses assessment of long-term transmission investment need carefully to maintain system reliability – reduce forced transmission outages, reduce customer outage durations and enhance grid resilience (also known as “hardening the grid”). As **Figure 13** emphasizes, TOs evaluate degrading asset performance, condition and maintenance cost levels in order to determine: (1) when action must be taken and (2) whether it's more reasonable and cost-effective to replace a transmission asset or repair it.

Figure 13. Transmission Asset Management – Repair vs Replace



Asset Evaluation Criteria

Each PJM TO's system has its own unique operating characteristics, topology, geography and load profile. Yet, across such diversity, common approaches and practices exist for evaluating transmission asset health. When prioritizing the modernization needs of the system, PJM TOs focus on evaluating asset condition and performance and the risk that the failure of each poses to the system and connected customers. Completing these evaluations help prevent failures that could impact grid stability, customer reliability and public safety. Specific methodologies may vary among TOs but, in general, the following asset criteria are used to prioritize grid needs and investments:

1. *Condition:* site inspections, asset physical characteristics assessment and condition-monitoring-system data analysis
2. *Performance:* reliability and availability metrics evaluation and assets' contributions to performance results
3. *Risk:* probability of asset failure and potential customer impacts

TOs evaluate these parameters against a number of factors in determining the scope and timing of mitigation plans: facility outage availability, siting requirements, availability of labor and material, constructability and available financial resources. Frequently, no single criterion drives decision-making. Rather, TOs employ methodologies that require both objective evaluation and engineering judgement.

Outcome of Criteria Evaluations

PJM TOs conduct a systematic series of asset assessments to gather a standard set of physical characteristics data associated with asset condition. Information gathered during asset assessments can be used to indicate the facility deterioration, current condition and future performance expectations. With this information in hand, TOs can determine if a transmission asset must be upgraded or replaced.

PJM TOs also measure assets' historical performance. They consider how assets have impacted system reliability and how they have affected customer service. Such assessment may also identify contributing factors to a facility's performance and outage probability. PJM TOs frequently review standard industry metrics like System Average Interruption Indices or Customer Minutes of Interruption as a means to quantify historical performance. When facility condition and performance have been quantified, TOs then prioritize asset modernization based on risk exposure. Numbers of customers served, load served and operational risk are all common risk criteria evaluated by TOs.

PJM Perspective

Managing existing infrastructure is an important complement to PJM's Regional Transmission Expansion Planning (RTEP) Process. PJM's process relies on the overarching assumption that existing TO facilities remain in good working order, as required under the terms of the Consolidated Transmission Owners Agreement. Transmission owner efforts to maintain the reliability of in-service facilities is integral to ensuring realistic outcomes from PJM's forward-looking transmission planning process. In practice, this requires ongoing diligence and upkeep. As the system ages, the approach must shift from simply maintaining assets to replacing and modernizing facilities as part of a coordinated planning effort.