3.0: RTO Obligations

As a Federally-approved RTO, PJM is charged with ensuring the safety, reliability and security of the bulk electric power system. PJM manages and controls Bulk Electric System (BES) real-time operation, market administration and provides comprehensive regional transmission expansion planning. PJM is responsible for administering a number of wholesale markets, including day-ahead and real-time energy markets, the long-term capacity market known as Reliability Pricing Model (RPM), Financial Transmission Rights auctions, and Regulation, Spinning Reserve, Black Start Service and Reactive Supply Ancillary Services markets.

PJM’s planning function assesses the grid 15 years into the future and directs enhancements to ensure compliance with North American Electric Reliability Corporation (NERC) planning standards, taking into account the long lead times required to build transmission infrastructure.

PJM is registered with the North American Electric Reliability Council (NERC) as the Reliability Coordinator (RC), Interchange Authority (IA), Transmission Operator (TOP), Balancing Authority (BA), Planning Authority (PA), Transmission Planner (TP), Transmission Service Provider (TSP) and Resource Planner (RP).

Transmission Planning Responsibilities

As part of its ongoing transmission planning responsibilities, PJM prepares the Regional Transmission Expansion Plan each year in order to analyze the electric supply needs of the customers in the PJM region. PJM applies NERC Reliability Standards to evaluate the reliability of the transmission system and determines the transmission upgrades needed to ensure those NERC Reliability Standards are met. Pursuant to FERC authority, PJM directs the building of new transmission projects or upgrades to ensure grid reliability to address near-term reliability needs and also assesses transmission options requiring a planning horizon of 15 years or more.

Figure 3.1: RTEP Process - RTO Perspective
The RTEP provides forward-looking information as to the state of the supply and delivery infrastructure and identifies future system needs, both in terms of reliability and market efficiency, as shown in Figure 3.1.

PJM’s RTEP directs transmission owners to address reliability needs through specified transmission solutions. Additionally, the information publicly disseminated through the RTEP process gives stakeholders, including generators, Demand Resource program providers, transmission owners and load serving entities the opportunity to address identified system needs in a manner that can defer or even obviate the need for RTEP-identified transmission solutions.

**Planning Process Authority**

PJM’s authority with respect to its planning process is based on its role as a FERC-approved RTO under its authority and responsibilities in the PJM Operating Agreement, PJM Tariff and Transmission Owner Agreement. Moreover, FERC approves the NERC Reliability Standards to which PJM plans and operates.

Among other functions, PJM is registered with NERC as Planning Authority, Transmission Planner and Reliability Coordinator with respect to compliance with NERC standards. PJM applies NERC Reliability Standards to evaluate the reliability of the transmission system and then determines transmission solutions needed to ensure those standards are met. In addition, PJM plans to ReliabilityFirst Corporation (RFC), Southeastern Electric Reliability Council (SERC), PJM and transmission owner (TO) criteria as applicable.

The authority for PJM to carry out its responsibilities is established by FERC’s approval of the PJM’s governing agreements, its approval of the NERC Reliability Standards and PJM’s designated roles with respect to those standards.
3.1: RTEP Process Description

PJM’s RTEP identifies transmission system upgrades and enhancements to provide for the operational, economic and reliability requirements of PJM customers. PJM’s region-wide RTEP approach integrates transmission with generation and load response options on a comparable basis to meet load-serving obligations.

PJM currently applies planning and reliability criteria over a 15-year horizon to identify system constraints and to develop the transmission enhancements to remedy them. Proposed transmission upgrades are examined for their feasibility, impact and costs, culminating in one plan for the entire PJM footprint.

Since its inception in 1997, PJM’s RTEP Process has continued to adapt to the planning needs of its members. Initially, PJM’s RTEP mainly comprised upgrades driven by load growth and generating resource interconnection requests. Today, PJM’s RTEP process considers many other drivers as well, as shown in Figure 3.2.

The rules and procedures for the RTEP process are set forth in Schedule 6 of the PJM Operating Agreement. In accordance with those rules, PJM prepares a plan for the enhancement and expansion of transmission facilities in the PJM region. Additionally, the PJM manuals describe the details of the RTEP process. In particular, PJM Manuals 14A and 14B describe PJM’s regional planning process and are accessible from PJM’s website via the following URL: http://www.pjm.com/documents/manuals.aspx.

Figure 3.2: RTEP Development Drivers
PJM’s RTEP process preserves the reliability of PJM’s interstate transmission system to ensure that power continues to flow reliably and efficiently to customers and that robust, competitive power markets continue to flourish. Fundamentally, regardless of the underlying driver of system expansion, the RTEP process must ensure all system needs are met reliably.

3.1.1 – Types of RTEP Upgrades
PJM develops transmission plans to resolve violations that could otherwise lead to system performance issues and loss of service to customers. These plans are examined for their feasibility, impact and costs and are discussed with PJM stakeholders throughout the RTEP process. This process culminates into a single recommended plan – one RTEP – for the entire PJM footprint that is subsequently submitted to PJM’s independent governing Board for consideration and approval. That approval then binds transmission owning utilities to construct the approved upgrades and new transmission facilities.

The outcome of PJM’s annual RTEP process is a PJM Board-approved set of Baseline and Network Upgrades, identification of attachment facilities for generator and merchant transmission interconnection requests, and review of Transmission Owner (TO) planned Supplemental upgrades. The status of PJM Baseline, Network and Supplemental upgrades can be found on the Construction Status page of PJM’s website, accessible via the following URL link: http://pjm.com/planning/rtep-upgrades-status/construct-status.aspx

Baseline Upgrades
Baseline assessments include base case thermal and voltage analyses, load deliverability thermal and voltages analyses, generation deliverability thermal and voltage analyses, common mode contingency analysis, voltage stability analysis, baseline stability analyses and n-1-1 thermal and voltage analyses. Contingency analysis includes all BES facilities, all tie lines to neighboring systems, critical neighboring system facilities and all lower voltage facilities operated by PJM. Thermal and voltage limits employed are those specified by PJM Operations, as described in the PJM Transmission Operations Manual M-3, available on PJM’s website via the following URL: http://www.pjm.com/documents/manuals.aspx.

The baseline component of PJM’s RTEP process includes:

- Solutions to address baseline transmission constraints revealed by reliability criteria violations observed in power-flow and related studies
- Cost responsibility allocations for baseline reliability upgrades
- Designating the entity to build the baseline transmission upgrade

Backbone baseline upgrades at 500 kV and above, are discussed in Sections 5, 6, 7 and 8. Baseline upgrades between 100 kV and 345 kV, are discussed in Section 9.

Network Upgrades
PJM’s RTEP also includes transmission upgrades identified through the System Impact Studies conducted as a part of PJM’s interconnection process. Such upgrades are necessary to interconnect new generation and merchant transmission facilities to the existing transmission grid and which would not otherwise have been necessary but for the interconnection request.

Network upgrades approved in 2010 are identified in the associated individual interconnection request System Impact Study reports, accessible from PJM’s queues on PJM’s website:


Direct Connection Upgrades
Direct Connection Upgrades are those transmission enhancements required of developers to “reach the bus” – interconnecting their proposed generators and merchant transmission facilities with the local transmission system. These facilities are also identified in individual System Impact Study reports. These study reports are accessible from PJM’s queues on PJM’s website, per the URLs cited above pertaining to Network Upgrades.
Supplemental Upgrades

Finally, Transmission Owners (TOs) can propose their own supplemental upgrades to strengthen their respective local systems. Such upgrades are not identified by PJM as required for compliance with regional system reliability, operational performance, or economic efficiency obligations. Supplemental projects are separately identified in the RTEP and are not subject to approval by the PJM Board. Supplemental upgrades are included as input assumptions to the RTEP. TOs identified 72 supplemental upgrades as part of PJM’s 2010 RTEP Process. Those upgrades are listed on the Transmission Construction Status website listed below: http://pjm.com/planning/rtep-upgrades-status/construct-status.aspx.

3.1.2 – Planning Criteria Compliance

PJM reliability planning encompasses a comprehensive series of detailed analyses that ensure reliability and compliance under the most stringent of the applicable NERC, Regional Entity (ReliabilityFirst Corporation or Southeastern Electric Reliability Council (SERC) as applicable), PJM and local transmission owner criteria.

To accomplish this, each year a comprehensive baseline assessment of all BES facilities over a 15-year planning horizon is performed. Studies are conducted to test whether the PJM system as planned can be operated to supply projected customer demands over a range of forecast system conditions as well as under contingency conditions that have a reasonable probability of occurrence.

Studies look 15 years into the future to identify transmission overloads, voltage limitations and other reliability standards violations. Details of these criteria are discussed in Section 3.2.

If any applicable reliability standard violations are identified, PJM is required to develop and implement solutions to solve those violations. These solutions must include a schedule for implementation, including expected in-service dates considering the lead times involved for the identified solutions. Subsequent annual assessments review the continuing need for the identified system facilities. PJM also is responsible for determining the assignment of any transmission expansion costs to appropriate parties, per established cost allocation provisions of PJM’s Operating Agreement.
3.2: NERC Planning Criteria

The Energy Policy Act of 2005 (EPAct 2005) created a Federal mandatory compliance and enforcement process for reliability standards to be overseen by FERC. Pursuant to EPAct 2005, FERC designated NERC as the Electric Reliability Organization for the United States. Mandatory compliance with NERC Reliability Standards began on June 1, 2007. Compliance is mandatory, and penalties for violation of FERC approved NERC Reliability Standards may be as high as $1 million per violation per day. PJM has applied the NERC Reliability Standards, and the PJM deliverability criteria used to apply them, on a mandatory basis since the initiation of the RTEP process in 1999.

PJM’s RTEP process rigorously applies NERC Planning Standards which specify a wide range of reliability tests that must be applied over both short-term and long-term planning horizons. In completing these assessments, PJM documents all conditions where the system did not meet applicable Reliability Standards and identifies system reinforcements required for compliance. Estimated costs and lead-times are also developed in collaboration with the transmission owners.

NERC Bulk Electric System (BES) Definition

A key concept in broader planning compliance terms is the definition of BES. Specifically, ReliabilityFirst Corporation (RFC) defines the BES as all of the following:

1. Individual generation resources larger than 20 MVA or a generation plant with aggregate capacity greater than 75 MVA that is connected via a 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 RFC definition of BES excludes:

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 step-up transformer); these 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.

An understanding of how BES facilities are defined facilitates understanding of planning standards and processes within PJM.

3.2.1 – NERC Category A

This reliability standard requires that the BES be tested with all facilities in service as defined in NERC Reliability Standard TPL-001. Facilities are identified which have pre-contingency flows exceeding applicable ratings. In addition, voltages are monitored for compliance with existing voltage limits specified by PJM Operations in Manual M-03, accessible from PJM’s website via the following URL link: http://www.pjm.com/~media/documents/manuals/m03.ashx.

3.2.2 – NERC Category B

Also known as the “n-1,” or “single contingency” criteria, this Reliability Standard requires that the BES be tested following the loss of a single generator, transmission circuit or transformer, per NERC Reliability Standard TPL-002.

In some cases, where the physical design of connections or breaker arrangements results in the outage of more than one faulted facility when the fault is cleared, the additional facilities are also outaged as a single event. If an existing relaying configuration is designed to remove more than one facility at the same time, multiple elements may be removed from service.
Facilities are identified which have post contingency flows equal to or higher than 100 percent of the applicable emergency rating. In addition, voltages are monitored for compliance with existing voltage limits specified by PJM Operations in Manual M-03, accessible from PJM’s website via the following URL link: http://www.pjm.com/~/media/documents/manuals/m03.ashx.

3.2.3 – NERC Category C
This Reliability Standard requires that the BES be tested for the loss of multiple facilities, as specified in NERC Reliability Standard TPL-003, for example, loss of a double circuit tower line or a substation bus. In addition, NERC Reliability Standard TPL-003 requires all Category B contingencies to be simulated followed by manual system adjustments, followed by another Category B contingency to ensure the system remains within applicable limits for NERC Category C3 contingencies. This is commonly referred to as the “n-1-1” criteria.

Facilities are identified which have post contingency flows equal to or higher than 100 percent of the applicable emergency rating. In addition, voltages are monitored for compliance with existing voltage limits specified by PJM Operations in Manual M-03, accessible from PJM’s website via the following URL link: http://www.pjm.com/~/media/documents/manuals/m03.ashx.

3.2.4 – NERC Category D
Also known as “Maximum Credible Disturbances,” PJM studies system conditions following a number of extreme events, judged to be critical from an operational perspective for risk and consequences to the system as specified in NERC Reliability Standard TPL-004.

3.2.5 – Contingencies Considered
Thermal and voltage analyses use a set of contingencies as required by NERC TPL standards. PJM employs a comprehensive set that includes every possible BES Category B and Category C contingency as described on Table 1 of NERC TPL standards. No Category B or Category C BES contingencies are excluded from the analysis.

- Over 7,600 TPL-002 category B contingencies were defined, including over 200 contingencies involving the loss of facilities in neighboring systems.
- Over 6,000 TPL-003 category C contingencies were defined, including over 100 contingencies involving the loss of facilities in neighboring systems.
- The n-1-1 NERC category C3 analysis considers every possible combination of category B contingencies, a total of over 57,000,000 combinations.

PJM's contingency set also includes an exhaustive set of single contingencies comprised of non-BES transmission elements modeled in the base case.

A limited set of multiple facility contingencies involving non-BES facilities is also included in the contingency set, given that issues on that system are not expected to propagate to BES facilities. A set of extreme, Category D contingencies are also tested.

Monitored Facilities
PJM power flow cases model all PJM BES facilities. PJM also monitors every tie line to neighboring systems regardless of voltage. In total, over 7,200 BES facilities are monitored as part of RTEP process analyses. A set of lower voltage, non-BES facilities monitored by PJM operations is also included in PJM planning studies. The reliability of neighboring systems is studied through the inter-regional planning process.

Planned Outages
Planned outages, including maintenance outages, are tested at load levels under which planned outages are performed.

3.2.6 – Compliance with NERC Criteria
PJM’s baseline assessments include base case thermal and voltage analysis, load deliverability thermal and voltage analyses, generation deliverability thermal and voltage analyses, common mode contingency analysis and baseline stability analysis. Contingency analysis includes all PJM BES facilities, all other lower voltage facilities operated by PJM, and critical facilities in systems adjoining PJM, including tie lines between systems. Thermal and voltage limits employed are those specified by PJM Operations, as described in the PJM Transmission Operations Manual M-3, available on PJM’s website via the following URL: http://www.pjm.com/documents/manuals.aspx.

Baseline thermal and voltage analysis encompasses an exhaustive analysis of all BES facilities for compliance with NERC Category A (TPL-001), Category B (TPL-002) and Category C (TPL-003) events. In addition, consistent with NERC standard TPL-004, a number of extreme events including those judged to be critical from an operational perspective.
Near-Term Analysis

PJM near-term analysis comprises a five-year-out baseline study as well as retool studies for years one through four.

PJM has conducted a comprehensive assessment of the ability of the PJM system to meet all applicable reliability planning criteria. NERC Planning Standards: http://www.nerc.com/page.php?cid=2|20.


- Transmission Owner Reliability Planning Criteria as contained in their respective FERC 715 filings and accessible from PJM’s website via the following URL link: http://www.pjm.com/planning/planning-criteria.aspx.


Facilities are identified with Category A pre-contingency flows that exceed applicable ratings. Facilities with post contingency flows equal to or higher than 100 percent of the applicable emergency rating are also identified. Bus voltages are also monitored based on the existing voltage limits used in PJM Operations. PJM documents all conditions for which the system do not meet applicable reliability standards and identified the system reinforcements required to bring the system into compliance. The RTEP process also includes development of estimated costs and lead-times to implement upgrades needed to resolve identified reliability criteria violations.

Retool Analysis

Each year during the RTEP process, PJM reviews transmission plans developed in earlier years to determine whether, as a result of changing assumptions, previously approved transmission upgrades are still required and, if so, whether they are still required in the year originally identified.

Frequent reanalysis using established methodologies also helps to identify and confirm chronic system weaknesses. When the same set of NERC Reliability Standard violations reappear with each successive analysis – even if near-term load forecast and system topology changes cause the violations to appear earlier or later than previous analyses may have indicated PJM knows that the repeated violations demand a meaningful solution.

Long-Term Analysis

PJM’s RTEP process 15-year planning horizon, exceeds the scope of that required by NERC criteria. Essentially, a 15-year forward analysis provides a load-growth sensitivity analysis, capturing the equivalent of higher than forecasted load levels, often the result of unforeseen extreme weather conditions.

This permits PJM to identify potential reliability criteria violations the solutions for which may require longer implementation lead-times. Fifteen-year forward results are reviewed to identify violations that occur for multiple deliverability areas or multiple or severe violations clustered in a specific area. Doing so allows PJM to determine if larger-scale, longer lead-time upgrades can be identified to address groups of violations collectively. In collaboration with transmission owners and other stakeholders, if transmission solutions can be identified, they can thus be considered for inclusion in RTEP.
3.3: RTEP Methodology – Thermal Analysis

Under PJM’s bright-line test, a thermal overload occurs on a Bulk Electric System (BES) facility if flow on that facility exceeds 100 percent of one of the following:

- The facility’s normal rating with all facility’s in service (i.e., NERC Category A)
- The facility’s emergency rating following the loss of a single facility (i.e., NERC Category B)
- The facility’s emergency rating following the loss of multiple facilities under a common mode contingency (i.e., NERC Category C)
- If the facility rating cannot be reduced below its normal rating following an n-1 event and subsequent system adjustments.

Each violation is documented for RTEP purposes in the first year in which a loading of 100 percent or more appears, and which continues to increase in magnitude in succeeding years during the study period.

PJM’s 2010 RTEP process scope encompassed analysis for 2011 through 2025 to ensure all applicable reliability planning criteria were met. These assessments included baseline load deliverability and generation deliverability tests, generally under peak load conditions. In its role as Transmission Planner, PJM uses deliverability criteria to define the critical system conditions under which BES facilities are tested, per NERC standards for Transmission Planners.

More specifically, PJM defines this criteria in the following terms: the transmission system must be robust enough to deliver established energy requirements into an area experiencing a capacity deficiency, per established load deliverability testing procedures. In addition, BES facilities must also be robust enough to deliver generation resources from an area experiencing higher than normal generation availability to the aggregate of PJM load.

3.3.1 – Load Deliverability

Load deliverability tests ensure that each of PJM’s 24 defined Load Deliverability Areas (LDA) satisfies NERC reliability criteria. PJM’s Western LDA included American Transmission Systems, Inc. (ATSI) in the 2010 cycle of analyses for the first time in anticipation of June 1, 2011 market integration.

The methodology requires that each LDA under test be modeled at a higher than normal load level — 10 percent probability of occurring — with higher than normal internal generation unavailability. Load deliverability studies test an LDA’s transmission systems capability to import sufficient energy to meet a defined Capacity Emergency Transfer Objective (CETO). Specifically, the scope of load deliverability tests encompasses the following:

- Assessment of the transmission system’s capability to deliver energy from the aggregate of all capacity resources to an electrical area experiencing a capacity deficiency.
- If the test fails, load is said to be bottled inside a defined LDA; sufficient capacity cannot be delivered to serve load as a result of limiting transmission constraints.
- Each LDA must be able to import its defined CETO in order to achieve a transmission risk Loss of Load Expectation (LOLE) of 1-event-in-25 years. Each LDA is tested for its expected import capability limit, or Capacity Emergency Transfer Limit (CETL). If CETL < CETO, the test fails, and additional transmission capability is needed.

Load deliverability tests assess Category A and Category B contingencies for both baseline studies and merchant transmission interconnection requests.

The PJM load deliverability testing methods are described in more detail in PJM Manual 14B, accessible from PJM’s website via the following URL link: http://www.pjm.com/~/media/documents/manuals/m14b.ashx.
**Capacity Emergency Transfer Objective**

The CETO calculated for the load deliverability test is the import capability required for the area to meet a LOLE risk level of one day in 25 years. The risk refers to the probability that an LDA would need to shed load due solely to its inability to import needed capacity assistance during a capacity emergency (i.e., the transmission system is not robust enough to import sufficient energy during a capacity emergency).

CETO is a probabilistic calculation that is based on the latest load and capacity data available at the time of the study. All load and capacity within the area under study is included in the CETO calculation. The latest resource data including updated generation outage rate information is included in the study. The PJM Load Forecast Report is used for modeling loads, and unrestricted peak loads are adjusted to account for changes in Energy Efficiency and Demand Resource programs. Load and generation models are adjusted for behind-the-meter (BTM) generation as required.

**3.3.2 – Generator Deliverability**

Generator deliverability testing ensures sufficient transmission capability to export generation capacity in excess of forecasted peak load from an area to the aggregate of PJM load. Specifically, the scope of generator deliverability tests the strength of the transmission system in the following terms:

- To ensure that the excess capacity of an aggregate of generators in a given area can be reliably transferred to the rest of PJM.

- To determine whether generation is bottled inside a defined area and cannot be exported to the rest of PJM.

The Generator Deliverability Testing Procedure is used to assess Category A and B contingencies as part of baseline analysis and as part of interconnection request studies.

**3.3.3 – N-1-1 Thermal**

As part of PJM’s analysis of NERC Category C events, PJM performs studies to determine if all monitored facilities can be operated within normal thermal and voltage limits after an actual n-1 contingency and within the applicable emergency thermal and voltage limits after an additional simulated contingency. The n-1-1 analysis monitored all BES facilities. The set of category B contingencies that was used to compile the C3 contingency pairs included all single contingencies in PJM regardless of voltage, all PJM tielines regardless of voltage, and selected contingencies in neighboring systems. The C3 contingency pairs that were considered included every possible combination of category B contingencies, a total of over 57,000,000 combinations. The n-1-1 analysis also analyzed the C3 contingency pairs in both possible orders to assess every combination and order of C3 event. Reinforcements were developed for areas where the system failed to meet the applicable normal rating after the first contingency or the applicable emergency rating after the second contingency.
3.4: Other Reliability Studies

3.4.1 – Short Circuit Studies

Short circuit analysis is performed to determine if any Bulk Electric System (BES) breakers exceed their interrupting capability. Calculated single phase to ground and three phase fault currents are compared to breaker interrupting capability provided by transmission owners. All breakers having ratings less than the calculated fault currents are identified and necessary upgrades determined. BES transmission upgrades identified as part of PJM’s 2010 Regional Transmission Expansion Plan (RTEP) process included a range of power system elements including circuit breaker replacements to accommodate increased current interrupting duty cycles.

Short circuit analysis is performed consistent with the following industry standards:

  
  This standard is used to provide short circuit current information for breakers and power system equipment used to sense and interrupt fault currents.


  This standard is used to establish the rating structure for circuit breakers and equipment associated with breakers.


    This standard is used to calculate the fault current on breakers that are rated on a Symmetrical Current Basis taking into consideration reclosing duration, X/R ratio differences, temperature conditions, etc.

  - **ANSI/IEEE C37.5-1979 – IEEE Guide for Calculation of Fault Currents for Applications of AC High-Voltage Circuit Breakers Rated on a Total Current Basis**

    This standard is used to calculate the fault current on breakers that are rated on a Total Current Basis.

Each of these standards is used jointly with transmission owners’ methodologies as a basis to calculate fault currents on all BES breakers.

By using these standards single phase to ground and three phase fault currents are calculated and compared to the breaker interrupting capability, provided by the transmission owners, for each breaker within the PJM footprint. All breakers whose calculated fault currents exceed breaker interrupting capabilities are considered overdutied and reported to transmission owners for confirmation. All breakers are used in specific short circuit cases which help to identify the cause and year breakers are likely to become overdutied.

Short circuit cases are built consistent with a one-year planning representation and a five-year planning representation. The one-year planning case consists of the current system in addition to all facilities planned to be in-service within the next year. The five-year planning case uses the one-year planning case as its base model and is updated to include all system upgrades, generation projects, and merchant transmission projects planned to be in-service within five years. The five-year planning case is consistent with the five-year PJM RTEP load flow base case.

Once an overdutied breaker is confirmed, breaker replacement and reinforcements along with cost estimates are determined. Breaker replacements and reinforcements, along with a schedule for implementation, are presented at monthly Transmission Expansion Advisory Committee (TEAC) stakeholder meetings.
3.4.2 – Stability Analyses

PJM performs multiple tiers of analysis to ensure the BES will remain stable, in compliance with NERC TPL standards, for system contingencies of reasonable probability consistent with those standards.

- **PJM System-Wide Analysis**
  PJM’s annual RTEP process transient stability assessment of the system is performed for one third of the network each year, so that the entire system is analyzed every three years. The analysis includes an evaluation of the system under light load conditions, typically the most challenging from a stability perspective.

- **Interconnection Request System Impact Studies**
  The analysis of proposed generation additions identifies any potential transient stability concerns between the new generator and the existing BES.

- **Operational Performance Issues**
  Transient stability assessments are also conducted on an as-needed basis when system topology changes occur or are proposed in areas with known, limited transient stability margin. These assessments are frequently driven by system conditions and events arising out of operations.

PJM’s 2010 RTEP process assessment confirmed compliance with established NERC system stability requirements.
3.5: RTEP Methodology – Reactive Analysis

NERC Reliability Standards require that a transmission system be stable and within applicable equipment thermal ratings and system voltage limits. PJM assesses system voltage levels under Category A, B and C contingencies to ensure system voltages will be within applicable limits and thus not violate NERC Reliability Standards.

If the voltage magnitude is outside prescribed limits or the change in voltage (voltage drop) following the loss of an element of the bulk electric system is greater than a specified amount, then system upgrades must be identified to resolve the criteria violations. Permissible voltage magnitudes and voltage drop percentages are determined based on operational conditions at each substation. PJM 500 kV voltage drop is limited at many 500 kV substations to 5 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 more detail in PJM Manual M-3, “Transmission Operations”, available on PJM's website via the following URL link: http://www.pjm.com/~media/documents/manuals/m03.ashx.

3.5.1 – Reactive Analysis – Deliverability

Consistent with deliverability studies for thermal criteria violations, PJM’s load deliverability testing methodology also evaluates compliance with reliability voltage criteria. Doing so ensures that the transmission system is able to deliver energy to an area experiencing a capacity deficiency. As part of this test, PJM establishes a Capacity Emergency Transfer Objective (CETO) for each load deliverability area (LDA), which is the amount of energy that the transmission system must be capable of delivering to the LDA being tested.
3.5.2 – Reactive Analysis – PV Curves

Reactive performance of the system can be analyzed through what is commonly called PV, or power-voltage, analysis. PV analysis allows system engineers to evaluate critical BES contingencies on system voltages as power transfers are increased across the transmission system or across a specific transmission facility. PV analysis can be used to show the existence of violations of NERC Reliability Standards, but can also be used to determine the point at which the system becomes unstable.

In a PV analysis, voltage conditions at a substation are represented on a curve. This shows the effect that increasing power transfers on a transmission line or set of lines has on voltage levels at the substation. Typically, as more power is transferred, voltage levels deteriorate. The more abrupt the decline in voltage level, the more difficult the voltage problem is to control operationally.

A PV curve depicts the MW transfer levels at which the voltage drop and voltage collapse violations are projected to occur. Voltage magnitudes are presented in two formats:

(i) at various substations as system power transfers into an area are increased; and,

(ii) on various transmission lines as post contingency power flows are increased on those lines.

PV curves show how increasing power transfers on a given line – often by only small amounts – can reach a critical point where further increases cause the transmission system to collapse. This critical point is known as the “steady state stability limit.”

PV analysis provides a much more rigorous examination of voltage collapse phenomena frequently foreshadowed by voltage magnitude and voltage drop results in load deliverability tests, tests intended to ensure that the transmission system is able to deliver energy to a portion of the system that is experiencing a capacity deficiency.

Voltage Collapse

Voltage collapse typically arises in planning studies following the loss of a transmission line or generator under heavy energy transfers into an area experiencing an available generation deficiency. In actual operations, voltage collapse can occur very quickly – within minutes or even fractions of seconds – and often results in a blackout to a portion of the system. An abrupt loss such as this can cascade to further instability across a much larger area as well.

To prevent the consequences of a potential voltage collapse situation, immediate action must be taken by system operators before transmission lines or related equipment fails or is permanently damaged, or before an irrecoverable voltage drop occurs.

The action may include turning specific generating plants off or on, opening or closing specific BES elements or discontinuing electric service to customers in specific areas. However, these are only temporary emergency measures and do not solve underlying systemic issues. On a long-term basis, new BES facilities or enhancements to existing ones become necessary.

3.5.3 – N-1-1 Voltage

The n-1-1 analysis also assesses applicable voltage magnitude and voltage drop limits. For voltage magnitude and voltage drop testing, PJM screens for potential voltage violations. Voltage violations include exceeding the normal low voltage limit after the first contingency, emergency low limit after the second contingency, or exceeding the emergency voltage drop limit after the second contingency. Reinforcements are developed for areas where voltage violations were identified.
3.6: Addressing Sub-Regional RTEP Issues

The PJM Regional Transmission Expansion Plan (RTEP) process addresses system reliability issues and viable solutions from both regional and sub-regional perspectives, essentially ignoring internal transmission owner (TO) zonal and state boundaries. Consequently, PJM is able to analyze and discern the true nature of power flows, their impact on reliability criteria violations and the optimal solutions within PJM to resolve them. The relationship between reliability criteria violation and upgrade location generally takes the form of one of the following scenarios:

1. Reliability criteria violations in a given TO zone may be driven by a local issue in that same zone. For example, local load growth may drive local transformer loadings and thus be the potential cause of a future overload on that facility.

2. Reliability criteria violations in one or more TO zones may be driven by or contributed to by some combination of system factors in another, potentially more distant, part of the PJM system. For example, voltage criteria violations in western portions of the PJM system may not be caused by a local problem but rather caused by some set of compounding factors contributing to heavier west-to-east transfers to more distant eastern load centers.

This perspective encompasses an RTO principle the FERC has continued to maintain – PJM can identify more economical and optimal solutions that consider all reliability criteria violations and congestion constraints that could be mitigated by one comprehensive set of expansion plans. Otherwise, consideration of reliability criteria violations individually, mutually exclusive of one another, can lead to economically inefficient resolution.

3.6.1 – Order 890 Compliance

PJM expanded its stakeholder process in 2008 in compliance with FERC's Order 890 to enhance coordinated, open and transparent planning, building on a well-established planning process codified in Schedule 6 of PJM’s Operating Agreement (OA). Looking to improve, valuable stakeholder discussions culminated in the establishment of three Sub-Regional RTEP Committees – Mid-Atlantic, Western and Southern – commissioned to review proposed upgrades of more local concern. Map 3.3 depicts PJM’s three sub-regions.

Each Sub-Regional RTEP Committee increases the opportunity for direct stakeholder participation in the planning process from initial assumption setting stages through review of the planning analyses, violations, and alternative transmission expansions. Each Sub-Regional RTEP Committee provides a more local forum for surfacing and considering planning issues. Interested parties can access PJM Sub-Regional RTEP Committee planning process information from PJM’s website via the following URL links:

- PJM Western Sub-Regional RTEP Committee: http://www.pjm.com/committees-and-groups/committees/ssrtep-w.aspx.
- PJM Southern Sub-Regional RTEP Committee: http://www.pjm.com/committees-and-groups/committees/ssrtep-s.aspx.

Through the activities of these committees, all PJM stakeholders have a forum to raise issues, propose solutions or alternatives and conduct other related discussions. These meetings are open to all stakeholders interested in the issues under consideration.

Each Sub-regional RTEP Committee is responsible for the initial review of Sub-regional RTEP upgrades within the TO zones that comprise each area. Any stakeholder can participate in any or all sub-regional activities on a voluntary basis. TOs that comprise each of the various sub-regions must participate in the sub-regional meeting that includes their area. PJM, with stakeholder input, may initiate additional sub-regional or local review deemed necessary or beneficial.
3.6.2 – Reviewing Sub-Regional RTEP Upgrades

RTEP upgrades are labeled as Regional RTEP Projects or Sub-Regional RTEP Projects, as defined in PJM’s Operating Agreement merely to make an initial categorization and posting of violations and upgrades. This more easily enables stakeholders to focus on upgrades and issues of specific interest. Regional RTEP Projects are those transmission expansions plans at voltages 230 kV and above. Sub-Regional RTEP Projects are those rated below 230 kV. This differentiation by voltage between Regional RTEP Projects and Sub-Regional RTEP Projects is made only for administrative convenience. **Section 9** summarizes upgrades by sub-region. **Section 14** summarizes upgrades by state jurisdiction.

**Mid-Atlantic Sub-region**

PJM operates the Bulk Electric System (BES) transmission facilities (and others monitored at lower voltage levels) throughout the Mid-Atlantic Sub-Region footprint shown in Map 3.3, including those of Atlantic City Electric Company (AE), Baltimore Gas and Electric (BGE), Delmarva Power and Light (DPL), Jersey Central Power and Light (JCPL), Metropolitan Edison Company (METED), Neptune, PECO Energy (PECO), Pennsylvania Electric Company (PENELEC), PEPCo Holdings (PEPCo), PPL Electric Utilities Corporation (PPL), Public Service Electric and Gas (PSEG), Rockland Electric (Rockland) and UGI Corporation (UGI). The Neptune Regional Transmission System interconnects with the Mid-Atlantic PJM transmission system at Sayreville substation in Northern New Jersey. The Linden variable frequency transformer (VFT) interconnects with the Mid-Atlantic PJM system at the Linden 230 kV Substation in New Jersey.

**Western Sub-Region**

PJM operates the BES transmission facilities (and others monitored at lower voltage levels) throughout the Western Sub-Region footprint shown in Map 3.3, including those of Allegheny Power (AP), American Electric Power (AEP), Commonwealth Edison (ComED), Dayton Power and Light (Dayton), Duquesne Light Company (DLCO) and American Transmission Systems, Inc. (ATSI).

**Southern Sub-Region**

PJM operates the BES transmission facilities (and others monitored at lower voltage levels) throughout the Southern Sub-Region footprint shown in Map 3.3, including those of Dominion Virginia Power (Dominion) which operates in Virginia and Northeastern North Carolina.
3.7: Public Policy Drivers

Since its 1997 inception, PJM’s Regional Transmission Expansion Plan (RTEP) process has adapted to expanding geographic markets, new and modified market offerings and other growing external and internal influences. 2010 was no exception. Sensitivity studies conducted as part of the 2010 RTEP cycle have evaluated the possible impact of emerging public policy initiatives on the need for backbone transmission facilities.

While sensitivity studies have been an integral part of PJM’s RTEP process, 2010 studies assessed a broader range of RTEP assumptions and impacts, the result of evolving public policy initiatives.

In 2010, PJM complemented its traditional bright-line tests with sensitivity analyses that incorporate a number of factors not typically taken into account under those tests, including the potential impact of state renewable portfolio standards, Demand Resource/Energy Efficiency efforts, and “at-risk” generation.

Section 4 discusses 2010 RTEP process results in light of emerging public policy trends.