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 BES real-time operation, market administration and provides comprehensive regional transmission expansion planning. This planning function assesses the grid 15 years into the future and directs enhancements to ensure compliance with NERC planning standards, taking into account the long lead times required to build transmission infrastructure.

Transmission Planning Responsibilities

As part of its ongoing transmission planning responsibilities, PJM prepares the RTEP 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.

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. The RTEP directs transmission owners to address reliability needs through specified transmission solutions. Additionally, the information publicly disseminated through the RTEP process gives other stakeholders, including generators, demand response 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.

* NOTE

PJM also administers a number of wholesale markets, including day-ahead and real-time energy markets, RPM Auctions, Financial Transmission Rights auctions, and Regulation, Spinning Reserve, Black Start Service and Reactive Supply Ancillary Services markets.
**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.

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 Summary Description

PJM’s Regional Transmission Expansion Plan (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 fifteen-year horizon to identify needed transmission enhancements to remedy identified system constraints. Proposed transmission upgrades are then 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 Web site 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 – RTEP Upgrades

PJM develops transmission plans to resolve violations that could otherwise lead to overloads 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 in one 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 TO planned Supplemental upgrades.

**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 and baseline stability analyses. Contingency analysis included 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 Web site 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

Baseline upgrades identified and approved in 2009 are discussed in Section 8.4.

**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 2009 are identified in the individual System Impact Study reports for the interconnection requests to which they are related. These study reports are accessible from PJM's queues on PJM's Web site:

**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 Web site, per the URLs cited above pertaining to Network Upgrades.

**Supplemental Upgrades**

Finally, Transmission Owners can propose their own “Supplemental” upgrades to strengthen their respective local systems. Such upgrades may not be 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.

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 (RFC or 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 and over a range of forecast system conditions as well as under contingency conditions that have a reasonable probability of occurrence. These studies test the transmission system against both mandatory national standards and PJM RTO standards.

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 and the methodologies used to identify violations of these criteria are discussed in Section 3.3.

If NERC Reliability Standards violations are identified, then 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 must review the continuing need for the identified system facilities. PJM also is responsible for recommending the assignment of any transmission expansion costs to appropriate parties, per established cost allocation provisions of PJM’s Operating Agreement.
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 transmission owners implementation.

**NERC Bulk Electric System (BES) Definition**
A key concept in broader planning compliance terms is the definition of Bulk Electric System (BES). Specifically, ReliabilityFirst 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 ReliabilityFirst Bulk Electric System 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 Web site via the following URL link: [http://www.pjm.com/~/media/documents/manuals/m03.ashx](http://www.pjm.com/~/media/documents/manuals/m03.ashx).

**3.2.2 – NERC Category B**
Also known as “n-1,” 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 the 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 were monitored for compliance with existing voltage limits specified by PJM Operations in Manual M-03, accessible from PJM’s Web site 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% of the applicable emergency rating. In addition, voltages were monitored for compliance with existing voltage limits specified by PJM Operations in Manual M-03, accessible from PJM’s Web site 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
The thermal and voltage analysis used 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 were excluded from the analysis. 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 was 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 were also tested.

- Over 7700 TPL-002 Category B contingencies were defined, including over 400 contingencies involving the loss of tie lines to neighboring systems, and 196 contingencies within neighboring systems.
- Over 4500 TPL-003 Category C contingencies were defined, including over 300 contingencies involving the loss of tie lines to neighboring systems, and 64 contingencies within neighboring systems.
- The n-1-1 NERC Category C3 analysis considers every possible combination of category B contingencies, a total of over 30,000,000 combinations.

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.

Planned Outages
Planned outages, including maintenance outages, were tested at load levels under which planned outages are performed.
3.3: RTEP Methodologies

The scope of the 2009 RTEP assessment included analysis for the period 2010 through 2024 to ensure the system meets all applicable reliability planning criteria. These assessments include baseline deliverability and generation deliverability tests, generally under peak load conditions.

In its role as Transmission Planner, PJM uses deliverability criteria to define “critical system conditions” which NERC standards require each Transmission Planner to establish under which the BES is tested.

More specifically, PJM defines this 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, the BES 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 23 defined Load Deliverability Areas (LDA) on the transmission system meets transmission system reliability criteria. To do so, each LDA is modeled at a higher than normal load level – 10 percent probability of occurring – with higher than normal internal generation unavailability. Deliverability tests transmission capability to import 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 maintain 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 Web site via the following URL link: http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

3.3.2 – Generator Deliverability
Generator deliverability testing ensures sufficient transmission capability to export generation capacity in excess of forecasted peak load from each 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 ensure that an individual generator during the System Impact Study phase of the generator interconnection request process can reliably deliver its capacity 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, B and C contingencies as part of baseline analysis and as part of interconnection request studies.
3.3.3 – Common Mode Contingencies
As part of PJM’s analysis of NERC Category C events, PJM performs studies to determine the impact of the loss of multiple facilities that share a common element or system protection arrangement. These include bus faults, breaker failures, double circuit tower line (DCTL) outages and stuck breaker events.

3.3.4 – Short Circuit Studies
Short circuit analysis was performed to determine if any BES breakers exceed their interrupting capability. Calculated single phase to ground and three phase fault currents were compared to breaker interrupting capability provided by the transmission owners. All breakers having ratings less than the calculated fault currents are identified and necessary upgrades are determined.

3.3.5 – 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.

• **MAAC Peak Load Stability**
  PJM has not historically been constrained by dynamic stability. As part of its 2009 RTEP process, PJM validated the reliability requirement. Specifically, in 2009, a 2013 MAAC Load Deliverability case, which modeled 90/10 summer peak load conditions was tested for NERC TPL standard Category B for high transfers into MAAC. Stability analysis results confirmed PJM dynamic stability.

• **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 2009 RTEP process assessment confirmed compliance with established NERC system stability requirements through 2014, as discussed in Section 8.4 and Section 8.5.
3.4: Scope of Modeling Impact Parameters

Each annual PJM RTEP process comprises re-evaluation of previous RTEP results. These re-evaluations are often referred to as retools and are driven by changes in planning assumptions.

From the perspective of process complexity, the greater the scope of planning parameter changes from year to year, the larger the effort to perform retool evaluations. The following summarizes major factors observed in PJM’s 2009 RTEP process which have impacted previously identified reliability criteria violations.

3.4.1 – Load Forecasting Trends: 2009 vs. 2008

PJM’s retool process ensures that RTEP evaluations keep pace with the most recent changes to assumptions and system conditions. Most notably, recent economic recessionary trends, since Fall 2008 have driven a lower short-term load forecast, a factor that has increased interest in PJM’s retool process (and was subsequently verified by PJM 2010 load forecast analysis.)

PJM issued a new load forecast report in January 2009 for the 2009 through 2024 planning horizon. PJM’s 2009 baseline model incorporated the 2009 Forecast. In summary, PJM’s 2014 RTO Summer Peak was modeled at 149,497 MW, less than the 2008 forecast for 2014 of 151,675 MW by 2,178 MW, or about 1.4 percent lower. Just as important, however, is that over the planning horizon, PJM’s forecasted 15-year RTO load growth rate increased from 1.5 percent per year in the 2008 forecast to 1.7 percent per year in the 2009 forecast.

Figure 3.3 compares the 2006, 2007 and 2008 PJM RTO summer peak load forecasts with the 2009 load forecast.

3.4.2 – Generation Trends

Changes in generation status constitute a primary driver of PJM retool analyses. In addition to existing in-service generation, retool analysis incorporates the impacts of various generation status changes including the following: generation with signed ISAs, generation with signed ISAs that have withdrawn and generation deactivations (e.g., retirement).

PJM’s queue-based, 3-study interconnection process offers developers the flexibility to consider and explore their respective generation interconnection business opportunities. 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. The process also establishes milestone
responsibilities for the developer, PJM and each Transmission Owner (TO) impacted by the request.

Recent trends in queue activity are shown in Table 3.1. This Table depicts a status snapshot of PJM’s entire interconnection queue, at the close of three successive yearly periods. These statistics demonstrate the dynamic nature of interconnection requests and ongoing queue activity.

This type of interconnection request activity is not unusual, considering the ebb and flow of developer business decisions in the face of regulatory uncertainties, economic conditions and tax credit availability. Nonetheless, more than 380 generation projects constituting more than 66,000 MW are currently active in PJM’s interconnection queues.

### Table 3.1: PJM Generation Interconnection Request Trends

<table>
<thead>
<tr>
<th></th>
<th>Close of Queue T (1)</th>
<th>Close of Queue U4 (2)</th>
<th>Close of Queue V4 (3)</th>
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<tr>
<td></td>
<td>MW</td>
<td># of Projects</td>
<td>MW</td>
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<tr>
<td>Active</td>
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<td>In-Service</td>
<td>21,172</td>
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<td>Suspended</td>
<td>937</td>
<td>11</td>
<td>2,866</td>
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<td>Under Construction</td>
<td>4,450</td>
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<tr>
<td>Withdrawn</td>
<td>140,061</td>
<td>442</td>
<td>157,865</td>
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<tr>
<td>Total</td>
<td>256,953</td>
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<td>277,058</td>
</tr>
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### Table 3.2: PJM Load Management and Energy Efficiency

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<tr>
<th></th>
<th>2009 Load Forecast Report</th>
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<tbody>
<tr>
<td></td>
<td>2009</td>
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<td>Mid-Atlantic</td>
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<td>a) Energy Efficiency</td>
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<tr>
<td>b) Load Management</td>
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<td>Total Load Management and Energy Efficiency</td>
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<tr>
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<td>b) Load Management</td>
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<td>a) Energy Efficiency</td>
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<tr>
<td>b) Load Management</td>
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<td>Total Load Management and Energy Efficiency</td>
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<td>PJM RTO</td>
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<td>a) Energy Efficiency</td>
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<tr>
<td>b) Load Management</td>
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</table>

* NOTE

Table 3.1
(1) As of close of Queue T on January 31, 2008
(2) As of close of Queue U4, January 31, 2009.
(3) As of close of Queue V4, January 31, 2010.

* NOTE

Table 3.2
At time of publication of the 2009 Load Report, no Energy Efficiency programs had been approved as RPM resources.
3.4.3 – Load Management Trends
RTEP process retool analyses also permit PJM to address the effects of load management including the impact of Demand Resources (DR) and Energy Efficiency (EE) that have cleared PJM’s Reliability Pricing Model (RPM) three-year-forward capacity market. See Table 3.2 and Table 3.3. Additional description of load management concepts can be found in Section 2.8.

Interruptible Load for Reliability (ILR) resources were treated as a stand-alone resource in RPM auctions for 2011 and all relevant years preceding that point. Subsequent to 2011, ILR has been subsumed into DR in RPM auctions, accounting for much of the significant increase in load management that has cleared in more recent auctions.

3.4.4 – Network Topology
In each retool study, those approved transmission system upgrades which are expected to be in service by June 1st of the year under study are included in the system model. In addition, approved long term firm transmission service requests are modeled, along with merchant transmission facilities which are expected to be in service during the year under study. The construction status of previously approved upgrades can be found on the PJM Web site at URL: http://www.pjm.com/planning/rtep-upgrades-status.aspx.

### Table 3.3: Load Management Components

<table>
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<th></th>
<th>2009</th>
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<tr>
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<td><strong>PJM RTO</strong></td>
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<td>3,456</td>
<td>3,456</td>
</tr>
</tbody>
</table>

*NOTE
Forecast represents the amount of Demand Resources cleared in RPM auctions plus the 5-year average of Interruptible Load for Reliability/Active Load Management. Winter load management is equal to Contractually Interruptible.
3.4.5 – Overview of 2009 Retool Studies

In 2009, PJM conducted retool analyses for the 2010, 2011, 2012 and 2013 systems to assess whether previously approved transmission upgrades are still required and, if required, whether they are still required in the year originally identified. Faced with changing system conditions, if the timing and nature of future reliability criteria violations and the progress of construction of previously identified transmission upgrades allow, those upgrades may need to be accelerated or may be deferred. PJM’s transmission plan is adjusted accordingly.

Section 4 through Section 7 provide the results of the 2009 retool analyses for 2010 through 2013, respectively. Each section provides a summary of key modeling assumptions and then highlights any changes resulting from the retool analysis. These results demonstrate the benefit of PJM’s dynamic planning process and its ability to adjust future plans to changing system conditions. This re-analysis helps to identify and confirm chronic system weaknesses, the result of a fundamental load-to-generation imbalance. When the same, or similar, set of applicable Reliability Standard violations reappear with successive analyses, even if near-term load forecast and system topology changes cause the violations to appear earlier or later than previous analyses may have otherwise identified, then examination of long-term solutions is pursued.

Section 4 discusses the results of the 2009 RTEP analysis of forecasted 2010 system conditions and revealed that the installation of a new 500 kV substation at Jack’s Mountain (formerly known as Airydale) can be deferred until 2012.

Section 5 discusses the results of the 2009 RTEP analysis of forecasted 2011 system conditions. The analysis re-affirmed the need for the 502 Junction - Loudoun 500 kV line (the TrAIL line) in 2011. The analysis also identified that a number of upgrades originally required in 2011 can be deferred until 2012 or, in one case, reduced in scope.

Section 6 discusses the results of the 2009 RTEP analysis of forecasted 2012 system conditions. This analysis re-affirmed the need for the Susquehanna - Roseland 500 kV line in 2012. The analysis also identified one project for which the need has been eliminated and another project which can be deferred until 2013.

Section 7 discusses the results of the 2009 RTEP analysis of forecasted 2013 system conditions. Based on this analysis, the need for the Amos - Welton Spring - Kemptown 765 kV line is now required to resolve thermal and reactive problems starting June 1, 2014. See Section 7.1 for details of the PATH Project.

The 2009 analysis also determined that the Possum Point to Indian River segment of the MAPP Project is not required until 2014, and the Indian River to Salem segment of the MAPP Project is not required within the current 15-year planning horizon. See Section 7.2 for additional discussion of the MAPP Project.