15.0: Overview

Since its 1997 inception, PJM’s Regional Transmission Expansion Planning Process has adapted to expanding geographic markets, new and modified market offerings and other growing external and internal influences. 2010 was no exception; 2011 will not be either. A number of RTEP challenges continue to engage PJM driven by PJM’s stakeholder sphere, public policy, U.S. economic conditions and other external factors driving industry change.

- **Section 15.1** summarizes proposed enhancements to PJM’s load forecasting methodology. Given the far-reaching RTEP impacts that load forecasts have, PJM and its stakeholders want to ensure that the load forecast is as accurate as possible and is adapted as necessary for changing circumstances.

Map 15.1: PJM Backbone Transmission System
• **Section 15.2** discusses the Demand Resource saturation analysis PJM completed in May 2010 to evaluate its reliability value in PJM. Prompted by recent increases in the amount of Demand Resources committed in PJM coupled with the limited interruption requirements of same, the study examined the point at which its reliability value saturates under current operational requirements regarding number and duration of interruptions.

• **Section 15.3** focuses on Renewable Portfolio Requirements. An increasing focus by federal and state governments on climate change and energy independence continues to make clear the critical role of the transmission system. For example, an important element of these policies is greater use of renewable resources, primarily wind. Integrating wind resources, often distant from the population centers that will use the electricity they produce, raises significant transmission public policy issues.

• **Section 15.4** discusses the impact of emerging industry technologies. PJM continues to assess the impact of smart grid technologies on price responsive demand and the impact of energy storage devices such as batteries on grid reliability.

• **Section 15.5** considers how PJM’s RTEP Process can be enhanced in light of recent FERC action on planning for public policy and addressing the proposals of non-incumbent transmission developers.

• **Section 15.6** discusses the methodology and preliminary results from PJM’s light load operational performance sensitivity study.

• **Section 15.7** addresses unfolding 2011 RTEP challenges in light of peak load reductions projected by the January 2011 PJM Load Forecast. That forecast takes into account significant econometric changes since January 2009 based on lower U.S. forecasted economic growth.
15.1: Load Forecasting Methodology Enhancements

A primary driver of PJM baseline reliability analysis is the growth of electrical peak load. Currently, PJM uses a set of models and a simulation process that forecast peak load growth for each transmission zone or Electric Distribution Company (EDC) within PJM.

On March 8, 2010, a group of stakeholders requested by letter that PJM retain an independent consultant to review PJM’s peak load forecasting methodology and make recommendations. The stated goal of the stakeholders was to ensure that the load forecast is as accurate as possible and can be adapted to changing circumstances. The consultant completed its work in September 2010 with a series of recommendations, subsequently reviewed by PJM and presented to the PJM Planning Committee.

15.1.1 – Methodology Background

PJM developed an internal load forecasting function beginning in 2004 and released its first independent load forecast in 2006. Fundamentally an econometric model, PJM’s load forecast produces estimates of non-coincident and coincident peak loads and net energy for load, for each PJM zone, locational deliverability area (LDA) and the RTO as a whole.

Load model parameters include local economic activity, weather and type-of-day variables. Weather data and economic forecasts are procured from outside vendors. The model itself features a Monte Carlo simulation of historical weather patterns and regional diversities to develop a distribution of forecasts that are then used to produce monthly and seasonal forecasts over a range of weather conditions.

Importance of the PJM Load Forecast

Projected summer peak loads from the January 2010 PJM forecast were modeled in 2010 RTEP power flow studies to identify baseline transmission upgrades needed to solve reliability criteria violations. PJM’s RTEP also assesses anticipated transmission needs to address the impact of long-term load growth requirements out through 2025.

Additionally, the load forecast is a key input to LDA emergency import capability Capacity Emergency Transfer Objective/ Capacity Emergency Transfer Limit (CETO/CETL) studies. CETO and CETL are themselves key input parameters to the Reliability Pricing Model (RPM) that drives forward capacity market activity.

Load forecasts are also required for the development of PJM’s installed reserve margin study which determines the generation reserves required to maintain a 1-day-in-10-year reliability index.

PJM supplies its load forecasts to the North American Electric Reliability Corporation (NERC), SERC Reliability Corporation (SERC) and ReliabilityFirst Corporation (RFC), for use in regional reliability assessments as well.

15.1.2 – Proposed Methodology Enhancements

Currently, the baseline peak forecast produced by PJM is driven by Moody’s Economy.Com baseline economic forecast, Moody’s best projection of long-run US economic growth. Those economic forecasts yield projections of Gross Metropolitan Product (GMP) used by PJM to develop projected load growth for each transmission owner (TO) zone. Moody’s provides GMP forecasts for metro areas that most closely align with the geography of each TO zone.

In pursuit of potential improvements, and at the request of stakeholders PJM commissioned a consultant-assisted study to evaluate whether other available methods potentially merit consideration by PJM to enhance how U.S. economic activity is incorporated into load forecast models.

Surveying Industry Methodologies

Following an RFP bid solicitation in May 2010, PJM engaged a consultant to work with PJM staff to conduct an industry survey to assess economic drivers, economic providers, and economic scenarios used throughout the industry to develop long-term sales and peak forecasts. The survey was conducted in two phases:

- Phase 1: Load Forecast Model Evaluation
- Phase 2: Weather Modeling Methods
The objective was to identify the range of methodologies used and the prevalence of those most commonly used. Both phases were completed in September and included a series of recommendations for PJM consideration.

**Phase 1 Load Forecast Model Evaluation**

Phase 1 looked at incorporating multiple economic forecasts. Such methods are used throughout the industry to generate energy and peak load forecasts. The consultant and PJM also examined alternative industry methods for quantifying load forecast uncertainty given economic uncertainty.

**Phase 2: Weather Modeling Methods:**

Alternative methods exist that could be used to address estimation and forecasting issues. For example, a variety of approaches are used by utilities to perform weather normalization calculations and to forecast system hourly loads and monthly peaks for long-run planning purposes. This phase of the project reviewed PJM’s method and alternative methods to determine if more appropriate ways exist to incorporate weather diversity into the forecast process.

**PJM Recommendations Based on Consultant Results**

Following issuance of the consultant’s September 2010 final report, PJM developed a position on each of the seven recommendations, summarized below, and presented them to the PJM Planning Committee in December 2010 for review, discussion and vote:

1. Implement a weighted economic index that combines multiple economic measures into a single index of economic activity
   - PJM’s position is that this recommendation merits further consideration.

2. Include rate shift variable for zones that have experienced significant rate increases.
   - PJM’s position is that this recommendation merits further consideration.

3. Combine the economic forecasts from Moody’s Economy.com and Global Insight to generate forecasts
   - PJM’s position is that this recommendation merits further consideration.

4. Track Moody’s and Global Insight performance of their three-year ahead forecast to adjust the relative vendor weighting of composite economic drivers
   - PJM’s position is that this recommendation merits further consideration.

5. Continue to use the simulation method. It is the best way to model diversity related to regional weather patterns
   - PJM’s position is that this recommendation merits further consideration.

6. Explore approaches that integrate weather variables with economic drivers that remove the impact of industrial load from interactive variables
   - PJM’s position is that this recommendation merits further consideration.

7. Allocate the RTO peaks to zones using the zone Coincident Peak (CP) values that occurred on peak days instead of the maximum zone CP for the month, and adjust only a single month to the seasonal peak unless there is a planning reason to adjust all months in the season
   - PJM’s position is that the CP allocation recommendation merits further consideration.

The complete consultant report is available on PJM’s website via the following URL links:

**Phase 1 – Load Forecast Model Evaluation:** [http://pjm.com/~media/committees-groups/committees/pacific-20101006/20101006-item-09-load-forecasting-recommendations-phase-1-findings.ashx](http://pjm.com/~media/committees-groups/committees/pacific-20101006/20101006-item-09-load-forecasting-recommendations-phase-1-findings.ashx)

**Phase 2 – Weather Modeling Methods:** [http://pjm.com/~media/committees-groups/committees/pacific-20101006/20101006-item-09-load-forecasting-recommendations-phase-2-findings.ashx](http://pjm.com/~media/committees-groups/committees/pacific-20101006/20101006-item-09-load-forecasting-recommendations-phase-2-findings.ashx)
15.2: Demand Resource Saturation

PJM completed a Demand Resource saturation analysis in May 2010 to evaluate its reliability value in PJM. Prompted by recent increases in the amount of Demand Resources committed in PJM coupled with the limited interruption requirements for it, the study examined the point at which its reliability value saturates given the following:

1. ten interruptions per year
2. a six hour duration per interruption.

Each of these requirements was investigated separately.

15.2.1 – Ten Interruption Requirement

Conceptually, a customer’s Demand Resource commitment to interrupt during peak demand periods eliminates the need for that customer to procure generation capacity for that portion of its load. PJM stakeholders recognized that this premise was valid only if Demand Resource customers (that committed no capacity to PJM) are interruptible over all loss-of-load risk periods so that their demand does not contribute to PJM’s loss of load probability (LOLP).

Determining a Demand Resource Saturation Level

The analysis examined the 2013/2014 delivery year. The general approach was to convolve the daily peak load distributions from the top 20 summer load days with the available capacity distribution to determine the frequency with which reserves would drop below a given threshold that would, in turn, trigger Demand Resource implementation, (assumed to be a 100 percent available capacity resource). The PJM reserve level was set to the approved IRM of 15.3 percent and the RTO Operating Reserve at which demand resources were invoked was set to 1,300 MW (as defined in Manual M-13, “Synchronized Reserve Requirement”).

If the margin between load and a specified level of available capacity is less than the operating reserve, Demand Resources are invoked (if available). No loss-of-load (LOL) occurs until the margin becomes less than or equal to zero. As the amount on the system increases, more generation is displaced and the expected number of times Demand Resources are invoked also increases. In addition, the probability of invoking Demand Resources ten or fewer times decreases. Or, put another way, the probability of needing Demand Resources more than ten times increases.

Based on the study results of Demand Response in more than 481 scenarios – each representing a particular weather pattern (13 scenarios from each of 37 historical weather years) – a penetration level was chosen at which the probability of needing more than ten interruptions was not too large. A limit of 8.5 percent was chosen as a reasonable saturation limit, given that it represents the point at which there exists only a 10 percent chance that more than ten interruptions would be needed; or, stated another way, a 90 percent chance of needing ten or fewer interruptions. Sensitivity studies indicated that the Demand Resource saturation level would increase to 11 percent if the interruption requirement were raised from ten to 15 interruptions per year.
15.2.2 – Interruption Duration

PJM also explored expanding the interruption window from six hours to ten hours to ensure the daily peak is not shifted to an off-peak period, assuming an 8.5 percent RTO Demand Resource limit.

The intent of Demand Resource programs is to shave daily peak load, not to shift the peak to an hour outside the established six hour window. If the Demand Resource amount increases to a certain level, however, the effect could be to shift the daily peak to an early afternoon hour or evening hour. If this occurred, the daily peak would not be reduced by the full amount of Demand Response, as illustrated in Figure 15.1.

**Demand Resource Implementation Example**

Figure 15.1 shows the hourly load curve from PJM’s all-time peak day of August 2, 2006. The red curve shows the unrestricted load. If Demand Resource had been implemented over the highest six load hours of that day, the metered load would have followed the blue curve. As illustrated in the figure, the impact shifts the daily peak to 1300 hours. As a result, the reduction in the daily peak is less than the amount of Demand Resource implemented.

To ensure the daily peak is reduced by the full amount of Demand Resources, the interruption window should be expanded to ensure that the daily peak still falls within the interruption window. Inspection of Figure 15.1 shows that the interruption window would need to be expanded to ten hours to ensure that the daily metered peak still falls within the window after full implementation, 8.5 percent of the unrestricted load as discussed in Section 15.2.1.

Alternatively, Figure 15.1 shows how to determine a limit on the amount of the current Demand Resource programs (requiring only six hours of interruption) that can be implemented without shifting the peak to an hour outside the interruption window. If the amount of Demand Resources is capped at the MW difference between the 1700 hour load and the 1300 hour load, implementing same for six hours will ensure the daily peak occurs within the interruption window and that the daily peak is reduced by the full amount of Demand Resources. Establishing such a cap would eliminate the need to expand the interruption window beyond the current requirement of six hours.
15.2.3 – Locational Deliverability Area (LDA) Analysis

The analysis described in Section 15.2.1 examined the likelihood of implementing Demand Resources across the entire PJM RTO due to an overall insufficient level of generation resources. They may also be implemented to relieve local reliability problems specific to an individual LDA.

PJM examined three LDAs of primary interest:

1. MAAC (consisting of the PJM Mid-Atlantic zones);
2. Eastern MAAC (consisting of the PSE&G, JCP&L, PECO, ACE, DPL and RE zones);
3. Southwestern MAAC (consisting of the PEPCO and BG&E zones).

The LDA analysis results indicate that, under current interruption requirements, the reliability value of Demand Resources saturates at 9.3 percent for MAAC, 14 percent for Eastern MAAC and 12.4 percent for Southwestern MAAC. The LDA analysis considered only interruptions required to address local, not RTO-wide, reliability problems.

Caps are expressed as a percentage of each LDA's forecasted PJM coincident peak. Importantly, these caps are based on each LDA's CETL for the 2013/2014 delivery year. Caps can change significantly for other delivery years given that the CETL is impacted by factors such as generator retirements and the completion or deferral of planned transmission upgrades.

15.2.4 – Demand Resources Saturation Report Details

The full PJM Demand Resources Saturation Report is available from PJM's website via the following URL link: [http://pjm.com/~media/committees-groups/committees/pc/20100811/20100811-item-10-demand-response-saturation-report.ashx](http://pjm.com/~media/committees-groups/committees/pc/20100811/20100811-item-10-demand-response-saturation-report.ashx).

15.2.5 – Next Steps / Status

The Demand Resource saturation issue was discussed extensively in the PJM stakeholder process throughout 2010. However, the discussions by the Planning Committee, Operating Committee, Market Implementation Committee, Markets and Reliability Committee and the Members Committee did not achieve consensus. As a result, PJM submitted a Section 205 filing with FERC on December 2, 2010 that proposed retention of the current Demand Resource product and, beginning with the 2014/15 delivery year, the establishment of two additional products, one available throughout the year – Annual Demand Resource – and one with an expanded summer commitment period compared to the current product (the expanded version known as Extended Summer Demand Resources). To distinguish the existing product from the two new products, PJM proposed to rename the pre-existing demand resources – Limited Demand Resources.

FERC issued an Order on January 31, 2011 accepting PJM’s proposed changes subject to certain new provisions in certain respects, to be submitted via compliance filing within 30 days of the January 31 Order, and subject to PJM submitting an informational filing in 180 days on its status.
15.3: Renewable Portfolio Requirements

An increasing focus by federal and state governments on climate change and energy independence continues to make clear the critical role of the transmission system.

For example, an important element of these policies is greater use of renewable resources, primarily wind. Integrating wind resources, often distant from the population centers that will use the electricity they produce, raises significant transmission public policy issues:

- Impacts on reliability and economic efficiency across multiple regions
- Amounts of transmission that should be built, where it should be built and who should pay for it

15.3.1 – Impacts on Jurisdictions within PJM

In PJM’s footprint, a number of jurisdictions have adopted renewable portfolio standards (RPS), requiring electricity suppliers to purchase specified amounts of renewable energy as part of their supply portfolio. Goals range from 10 percent to 25 percent, as shown in Table 15.1.

15.3.2 – Wind Potential

Much of the wind potential in PJM is clustered in three areas: along the Appalachian Mountains; in the Midwest, particularly in the Great Plains; and off the East Coast, as shown on Map 15.2.

Regardless of location, new transmission will be needed to deliver that power to population centers where it is needed.

Active interconnection requests through January 31, 2011, include nearly 42,000 MW of wind generation, 420 MW of methane, 700 MW of biomass, 1,160 MW of hydro and 4,200 MW of solar.

The public policy sensitivity studies discussed in Section 4 address the impacts of renewable generation on the need for existing, approved backbone transmission lines.

Intermittent Resources

While some renewable resources can operate in a manner similar to the traditional fossil fueled power plants, other renewable energy sources, such as wind, are recognized as intermittent resources. Their ability to generate power is directly determined by the immediate availability and/or magnitude of their specific fuel. For example, wind turbines can generate electricity only when wind speed is within a range consistent with the physical specifications of the related turbines.

This presents challenges with respect to real-time operational dispatch and specific capacity value. To address the latter issue, PJM has established a set of business rules unique to intermittent resources that provide for the determination of capacity values sufficiently credible to represent capacity during the PJM summer peak period. These are described in PJM Manuals M21 (http://pjm.com/~media/documents/manuals/m21.ashx) and M14A (http://pjm.com/~media/documents/manuals/m14a.ashx).

15.3.3 – Demand Resources and Energy Efficiency (EE)

Demand Resources and EE are important resources for meeting customers’ electricity needs. PJM integrates demand response and energy efficiency programs to the extent these resources clear PJM market auctions. When PJM Regional Transmission Expansion Plan (RTEP) studies reveal that these resources are insufficient to serve load within established reliability standards, PJM proposes transmission upgrades to resolve identified violations of those standards.
### Table 15.1: RPS Initiatives in PJM States

<table>
<thead>
<tr>
<th>Regulation or Legislation</th>
<th>Geographic Eligibility</th>
<th>Alternative Compliance Payment (ACP)</th>
<th>Credit Multipliers</th>
<th>Year</th>
<th>RPS Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>DC</strong></td>
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<tr>
<td>Bill 17-0492 (2008)</td>
<td>(1) located in the PJM Region or in a state that is adjacent to the PJM Region; or</td>
<td>Tier 2 - $10/MWh</td>
<td>b). 110% credits for wind or solar Energy between 1/1/2007 and 12/31/2009</td>
<td></td>
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</tr>
<tr>
<td>Bill 18-0223 (2010)</td>
<td>(2) outside the area described in item (1) but in a control area that is adjacent to the PJM Region, if the electricity is delivered into the PJM Region.</td>
<td>Solar - $300/MWh in 2007 and 2008, $500/MWh in 2009 thru 2014, declining thereafter.</td>
<td>c). 110% credits for Methane from landfill or sewage treatment until 12/31/2009</td>
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<td>(3) Solar resource must be located in within D.C. unless all resource options have been exhausted.</td>
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<td><strong>DE</strong></td>
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<tr>
<td>Senate Bill 74 (2005)</td>
<td>“Eligible Energy Resources” include energy resources located within or imported into the PJM region.</td>
<td>$25/MWh for 1st deficient year.</td>
<td>a). 300% credit for (1) in-state solar electric or (2) renewable fuel cells installed on or before 12/31/2014.</td>
<td>2025/26</td>
<td>Total – 25%</td>
</tr>
<tr>
<td>Senate Bill 19 (2007)</td>
<td></td>
<td>$50/MWh for 2nd deficient year.</td>
<td>b). 150% credit for wind energy installations sited in Delaware on or before 12/31/2012.</td>
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<tr>
<td>Senate Bill 328 (2008)</td>
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<td>$80/MWh for 3rd+ deficient year.</td>
<td>c). 350% credit for wind energy installations sited off the DE coast on or before 5/31/2017.</td>
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<tr>
<td>Senate Bill 119 (2010)</td>
<td></td>
<td>Solar ACP: $400/MWh for 1st deficient year, $450/MWh for 2nd deficient year, $500/MWh for 3rd+ deficient year</td>
<td>d). 110% credit for solar or wind installations sited in Delaware for which at least 50% of the equipment or components are manufactured in Delaware or installed with a minimum 75% state workforce.</td>
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<tr>
<td><strong>IL</strong></td>
<td>Public Act 095-0481</td>
<td>None. Resources must be “cost-effective.”</td>
<td>N/A</td>
<td>2025/2026</td>
<td>25%</td>
</tr>
<tr>
<td>H.B. 6202 (2010)</td>
<td>Eligible resources must be located in IL. If there are insufficient cost-effective in-state resources, resources can be procured from adjoining states, and if these are also not cost-effective, resources can be procured from other regions of the country.</td>
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<tr>
<td><strong>MD</strong></td>
<td>Public Act 295 (2008)</td>
<td>Renewable energy credits used to satisfy the renewable energy standards shall be either 1) located anywhere in this state or 2) located outside of this state in the retail electric customer service territory of a utility recognized by the Michigan PSC.</td>
<td>Not applicable for the Renewable Energy Requirement.</td>
<td>2015</td>
<td>10%</td>
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<td></td>
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<td>Tier 1 - $40 / MWh</td>
<td>a). Solar receives an additional 2 credits per MWh.</td>
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<td>Tier 2 - $30 / MWh</td>
<td>b). Lesser bonuses awarded for on-peak production, storage, and using in-state labor or equipment.</td>
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<td></td>
<td>Solar - $450 / MWh in 2008 $400 / MWh in 2010, declining to $50 / MWh in 2023</td>
<td>For generating facilities placed in service after January 1, 2004:</td>
<td>2022</td>
<td>Total – 20%</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>a). 120% credits for wind Energy before 12/31/2005</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>b). 110% credits for wind Energy between 1/1/2006 and 12/31/2008</td>
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<td></td>
<td>c). 110% credits for Methane from landfill or sewage treatment until 12/31/2008</td>
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</table>
### Table 15.1: RPS Initiatives in PJM States (Continued)

<table>
<thead>
<tr>
<th>Regulation or Legislation</th>
<th>Geographic Eligibility</th>
<th>Alternative Compliance Payment (ACP)</th>
<th>Credit Multipliers</th>
<th>RPS Year</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>NC SB 3 (2007)</td>
<td>Utilities may use unbundled RECs from out-of-state renewable energy facilities to meet up to 25% of the portfolio standard. Qualifying out-of-state facilities are (1) hydroelectric power facilities with a generation capacity up to 10 MW, or (2) renewable energy facilities placed into service on or after January 1, 2007.</td>
<td>None. Recoverable costs are capped.</td>
<td>Triple credit for every one REC generated by the first 20MW of biomass facility located in a “cleanfields renewable energy demonstration park” as defined by SB 886.</td>
<td>2021</td>
<td>12.5%</td>
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<td>NC SB 960 (2009)</td>
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<tr>
<td>NC SB 886 (2010)</td>
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<tr>
<td>NJ N.J.A.C 14:4-8 - (2004)</td>
<td>Energy shall be generated within or delivered into the PJM region. If the latter, the Energy must have been generated at a facility that commenced construction on or after January 1, 2003.</td>
<td>Class I &amp; II (ACP) - $50/MWh</td>
<td>N/A</td>
<td>2020/2021</td>
<td>Class I – 17.8% Total – 22.5% Solar - 5,316 GWh (2020)</td>
</tr>
<tr>
<td>NJ AB 3520 (2010)</td>
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<td>NJ SB 2036 (2010)</td>
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<tr>
<td>OH SB 221 (2008)</td>
<td>At least 50% of the renewable energy requirement must be met by in-state facilities and the remaining 50% with resources that can be shown to be deliverable into the state.</td>
<td>REC - $45/MWh</td>
<td>N/A</td>
<td>2024</td>
<td>12.5%</td>
</tr>
<tr>
<td>PA Senate Bill 1030</td>
<td>Sources located inside the geographical boundaries of this Commonwealth or within the service territory of any regional transmission organization that manages the transmission system in any part of this Commonwealth.</td>
<td>Tier I &amp; Tier II - $45 / MWh</td>
<td>N/A</td>
<td>2020/2021</td>
<td>Tier I – 8.0% Total – 18.0%</td>
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<td>PA Act 213,</td>
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<td>PA HB 1203 (2007)</td>
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<td>PA Act 35</td>
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<tr>
<td>VA SB 1416 (2007)</td>
<td>Electricity must be generated or purchased in Virginia or in the interconnection region of the regional transmission entity.</td>
<td>None. Voluntary goal.</td>
<td>a). One credit per MWh from alternative energy resource facilities.</td>
<td>2022</td>
<td>12%</td>
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<td>VA SB 718 (3/2008)</td>
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<td>VA HB 1022 (2010)</td>
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<tr>
<td>WV H.B. 408 (2009)</td>
<td>Electricity produced must be generated or purchased from a facility in West Virginia or in the PJM Service Territory</td>
<td>The Less of:</td>
<td>a). One credit per MWh from alternative energy resource facilities.</td>
<td>2025</td>
<td>25%</td>
</tr>
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<td>WV S.B. 350 (2010)</td>
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</table>

**Table Notes:**
- **NC:** North Carolina
- **NJ:** New Jersey
- **OH:** Ohio
- **PA:** Pennsylvania
- **VA:** Virginia
- **WV:** West Virginia
Map 15.2: Clustered Wind Generation (through close of Queue W4 on January 31, 2011)
**Evolving Public Policy**

Initiatives to integrate ever growing amounts of generation powered by renewable resources continue to unfold at the federal and state levels of government. PJM remains engaged in efforts at each level in order to ensure that planning, operating and market functions remain able to accommodate them.

Energy Efficiency (EE) standards are under development or are already included in RPS programs in a number of PJM states. The statuses of programs for jurisdictions within PJM are highlighted in Table 15.2. EE standards promote moderation in peak demand growth and energy. PJM supports these efforts and is closely monitoring developments to anticipate complementary modifications to enhance markets and transmission planning.

The public policy sensitivity studies discussed in Section 4 address the impacts of Demand Resource and EE programs that have cleared PJM’s Reliability Pricing Model (RPM) base residual auction on the need for existing, approved backbone transmission lines.
### Table 15.2: Energy Efficiency and Demand Response Programs in PJM, by Jurisdiction

<table>
<thead>
<tr>
<th>State</th>
<th>Energy Efficiency (Energy Use Reduction) Goal</th>
<th>Demand Resource (Peak Load Reduction) Goal</th>
</tr>
</thead>
<tbody>
<tr>
<td>DE</td>
<td>2% by 2011 and 15% by 2015 (base year 2007)</td>
<td>2% by 2011 and 15% by 2015 (base year 2007)</td>
</tr>
<tr>
<td>DC</td>
<td>None in place or proposed</td>
<td>None in place or proposed</td>
</tr>
<tr>
<td>IL</td>
<td>Incremental energy savings of 0.2% (two tenths of one percent) each year over the prior year from 2008 to 2015 (2% by 2015 and every year thereafter)</td>
<td>Reduction of 0.1% (one tenth of one percent) over the prior year each year for 10 years (starting in 2008) for eligible retail customers</td>
</tr>
<tr>
<td>IN</td>
<td>An “overall annual energy efficiency savings goal of 2% to be achieved by jurisdictional electric utilities … within 10 years, with interim savings goals…to be achieved in years one through nine”. Those interim goals are 0.3% in 2010, 0.5% in 2011, 0.7% in 2012, 0.9% in 2013, 1.1% in 2014, 1.3% in 2015, 1.5% in 2016, 1.7% in 2017, 1.9% in 2018 and 2.0% in 2019.</td>
<td>None in place or proposed</td>
</tr>
<tr>
<td>KY[1]</td>
<td>Offset at least 18% of the state’s projected 2025 energy demand</td>
<td>Offset at least 18% of the state’s projected 2025 energy demand</td>
</tr>
<tr>
<td>MD</td>
<td>5% by the end of 2011 and 10% by the end of 2015 in per capita electricity consumed in each electric company's service territory during 2007</td>
<td>5% by the end of 2011, 10% by the end of 2013, and 15% by the end of 2015 in per capita peak demand of electricity consumed in each electric company's service territory during 2007</td>
</tr>
<tr>
<td>MI</td>
<td>An electric providers energy optimization programs must collectively achieve minimum energy savings based on total annual retail electricity sale of 0.3% in years 2008 - 2009, 0.5% in 2010, 0.75% in 2011 and 1% in 2012, 2013, 2014 and 2015. The “total annual retail electricity sale” refers to the weather normalized total annual retail electric sales in megawatt hours for the prior year.</td>
<td>An electric providers energy optimization programs must collectively achieve minimum energy savings based on total annual retail electricity sale of 0.3% in years 2008 - 2009, 0.5% in 2010, 0.75% in 2011 and 1% in 2012, 2013, 2014 and 2015. The “total annual retail electricity sale” refers to the weather normalized total annual retail electric sales in megawatt hours for the prior year.</td>
</tr>
<tr>
<td>NJ[2]</td>
<td>Energy efficiency and renewable energy power savings of 3% of prior-year electricity sales in 2012, 6% in 2013, 10% in 2014, 15% in 2015, 15% in 2016, 17% in 2017, 19% in 2018 and 20% in 2019</td>
<td>Energy efficiency and renewable energy power savings of 3% of prior-year electricity sales in 2012, 6% in 2013, 10% in 2014, 15% in 2015, 15% in 2016, 17% in 2017, 19% in 2018 and 20% in 2019</td>
</tr>
<tr>
<td>OH</td>
<td>Savings of at least 0.3% of the total, annual average and normalized kWh sales of the electric distribution utility during the preceding three calendar years to customers in the state, an additional 0.5% in 2010, 0.7% in 2011, 0.8% in 2012, 0.9% in 2013, 1% from 2014 to 2018, and 2% each year thereafter, achieving a cumulative annual energy savings in excess of 22% by the end of 2025.</td>
<td>1% in 2009 and an additional 0.75% each year through 2018</td>
</tr>
<tr>
<td>PA</td>
<td>1% of 2009-2010 sales by May 31, 2011, increasing to 3% by May 31, 2013 (10% of reductions is to come from federal, state, and local government, including municipalities, school districts, institutions of higher education, and nonprofit entities)</td>
<td>4.5% of 2009-2010 sales by May 31, 2013 (10% of reductions is to come from federal, state, and local government, including municipalities, school districts, institutions of higher education, and nonprofit entities)</td>
</tr>
<tr>
<td>TN</td>
<td>None in place or proposed</td>
<td>None in place or proposed</td>
</tr>
<tr>
<td>VA</td>
<td>10% (from 2006 levels) by 2022</td>
<td>None in place or proposed</td>
</tr>
<tr>
<td>WV</td>
<td>Earn credits equivalent to 10% of the electric energy sold in the prior year (2015-2019), 15% (2020-2024), and 25% (2025 and thereafter); one credit earned for each MWh conserved</td>
<td>Earn credits equivalent to 10% of the electric energy sold in the prior year (2015-2019), 15% (2020-2024), and 25% (2025 and thereafter); one credit earned for each MWh conserved</td>
</tr>
</tbody>
</table>

[1] Goals in statewide energy plan, not legislation

[2] Goals in New Jersey’s Energy Master Plan, not legislation and are subject to change in the near future

[3] A combination of energy efficiency (3,300 MW), combined heat and power (1,500 MW), and demand response programs (900 MW). Subject to change in the near future.
15.4: The Impact of Emerging Grid Technologies

PJM continues to assess the impact of unfolding grid technologies on the Regional Transmission Expansion Plan (RTEP) process at many levels.

15.4.1 – Price Responsive Demand and Smart Grid Technology

A growing number of states and utilities within PJM are pursuing Demand Resource programs based on dynamic and time-differentiated retail prices and utility investments in Advanced Metering Infrastructure (AMI), often as part of smart grid initiatives. Such developments could potentially yield significant amounts of Price Responsive Demand (PRD), demand that predictably responds to changes in wholesale prices.

While PJM does not expect PRD to displace the overall future need for transmission additions, significant levels of PRD have the potential to provide system reliability benefits both from an operating perspective and planning perspective.

A key benefit is the ability to fulfill obligations to achieve Loss of Load Expectation (LOLE) objectives. Essentially, demand reduction from Price Responsive Demand has the real potential to reduce the planning reserves required to meet LOLE based reliability standards. From a planning perspective, other key benefits may potentially also include the following:

- Defer the need for generation investment
- Reduce transmission line losses
- Defer the need for transmission investment
- Reduce environmental impacts

PJM will continue in 2011 to engage stakeholders in process and business rule discussions regarding Committed and Uncommitted PRD and their impact on load forecasting and other aspects of PJM’s RTEP process. PJM anticipates finalizing these and a number of other PRD processes and business rules in 2011 through PJM committee stakeholder forums.

15.4.2 – Capacity Value – Batteries and Storage

PJM’s interest in electricity storage reflects the fact that much more storage capacity will be needed to address a major expansion of intermittent renewable energy sources and their impact on system reliability. Currently, grid operators like PJM face issues associated with the inability to store electricity for use at peak demand periods when wind generators or other intermittent power sources are often not available.

Energy Storage Devices (ESDs) draw electricity off the grid, store it and discharge it back onto the grid for use at a subsequent point in time. While ESDs do not fit neatly into a traditional category of assets, be it transmission, generation, or distribution, given their ability to perform multiple functions, such storage devices are capable of resolving reliability concerns by, among other things, mitigating normal transmission overloads, addressing transmission line trips and providing contingency voltage support. Given their ability to “move” energy from off-peak to on-peak, ESDs can also provide power to mitigate capacity shortage conditions.

PJM continues to monitor the emergence of ESDs in to be prepared to assess their impact on PJM Bulk Electric System (BES) facilities as part of each annual RTEP cycle.
15.5: RTEP Process: Considering Alternate Transmission Proposals

PJM has re-chartered the Regional Planning Process Task Force (RPPTF, formerly the Regional Planning Process Working Group) to undertake a stakeholder process with the following scope:

1. Evaluate and make recommendations to implement additional planning criteria or procedures to include a broader range of assumptions that would be required to plan for public policy initiatives such as renewable resource integration, demand response programs, or other environmental initiatives. In the event additional planning criteria is proposed to address public policy initiatives, assess the impact of the proposed criteria on the current interconnection queuing processes and procedures and make recommendations as required.

2. Evaluate and make recommendations on modifying or expanding PJM criteria or procedures related to “at risk” generation in the RTEP.

3. Evaluate PJM’s current method for designating entities to construct and own RTEP baseline upgrades and modify existing RTEP processes and procedures for PJM to consider alternate transmission project proposals and to prioritize and choose among competing projects.

15.5.1 – FERC Transmission Planning NOPR - RM10-23-000

PJM jointly (as part of the ISO/RTO Council) and separately of its own accord submitted comments in response to the FERC’s June 17, 2010 NOPR – Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities – in Docket RM10-23-000. The purpose of the NOPR is to address remaining deficiencies that the Commission finds still exist following implementation of Order No. 890. In its comments, PJM outlined the NOPR proposals it supports, as well as those where PJM believes further work is needed. The full text of PJM and ISO/RTO Council comments are available from PJM’s web via the following URL links:

**PJM**


**ISO/RTO Council**


**NOPR - Public Policy Driven Projects**

FERC proposes to revise Order No. 890 requirements regarding local and regional transmission planning processes to require each transmission provider (TP) to:

- Amend its OATT to explicitly provide for consideration of public policy requirements established by state or federal laws or regulations that may drive transmission needs.

- After consulting with stakeholders, a TP may include in the RTEP process additional public policy objectives not specifically required by state or federal laws or regulations.

The proposed requirement would supplement (not replace) existing requirements with respect to consideration of reliability and economic planning. FERC does not propose to identify public policy requirements, rather NOPR proposes to require each TP to:

- Coordinate with its customers and stakeholders to identify public policy requirements established by state or federal laws or regulations appropriate to include in its local and regional transmission planning process.

- Specify in its OATT the procedures and mechanisms for evaluating projects proposed to achieve public policy requirements established by state or federal laws or regulations.
This proposed requirement would not establish an independent obligation to satisfy public policy requirements established by state or federal laws or regulations.

**Proposed Reforms Regarding Non-incumbent Developers**
PJM and its stakeholders continue to monitor the FERC’s unfolding policies in a number of areas in so far as they impact transmission proposals by non-incumbent developers, including the following:

- Elimination of Right-of-First Refusal (ROFR) provision from RTO Tariffs

- Tariff revisions to demonstrate that RTEP has established appropriate qualifying criteria, included in the Tariff, for determining an entity’s eligibility to propose an RTEP project, e.g., necessary financial and technical expertise to construct, own, operate and maintain transmission facilities.

- Tariff mechanism that addresses selection criteria among similar and modified proposals. The mechanism must be able to determine which proposal a modified project is most similar to with the sponsor of the most similar project having the right to construct and own.

- Non-incumbent developer must have opportunity comparable to incumbent TO.

**15.5.2 Primary Power Order**
PJM’s RTEP process has also been impacted by FERC’s Primary Power Declaratory Order. That Order addresses a non-incumbent transmission developer that seeks to be eligible to propose and be designated to build a transmission facility project under PJM’s RTEP and seek cost based rates.

FERC’s Order found that the PJM Tariff permits, but does not require PJM to designate such an entity to propose, construct, own and finance RTEP project as a baseline reliability or economic project. Nonetheless, PJM would have to “adequately justify” its action if it denied the sponsor of the project the right to construct and receive economic benefit.

To the extent PJM believes that additional Tariff language would be helpful in processing such filings, PJM may make a FERC Section 205 filing to clarify its Tariff.

**15.5.3 – Central Transmission Order**
In this case before the FERC, Central Transmission lodged an FPA Section 206 Complaint alleging that Schedule 6 of PJM’s Operating Agreement and Schedule 12 of PJM’s Tariff were unjust, unreasonable and unduly discriminatory.

Consistent with the finding in Primary Power, FERC found that if approved through the RTEP, Central Transmission, a non-incumbent transmission developer, is eligible under the Tariff and Operating Agreement to be designated to construct its economic enhancement project and seek Schedule 12 cost rate treatment. The Complaint was dismissed; FERC found that ordering Tariff and Operating Agreement changes under a Section 206 filing was unnecessary.
15.6: RTEP Process: Light Load Operational Performance

PJM initiated stakeholder discussions in 2010 to establish RTEP process enhancements to address light load system conditions. Process enhancements will require input parameter assumptions for off-peak load levels, generation dispatch by fuel type, interchange with adjacent areas and scope of study analyses.

Proposed Methodology

PJM has proposed to model the variability of wind generation during light load periods by assessing the ramping impact of wind resources using analysis similar to the generation deliverability test. NERC Category A, B, C (except C3) tests would be applied.

As part of an initial sensitivity analysis, PJM modeled light load at 50 percent of 50/50 summer peak demand on a five-year-forward power flow case. Dispatch in the power flow case was established through a review of historical operating data. Oil and gas fired units, generally off-line at light load levels, were modeled off-line in the case. Coal and nuclear units were modeled as on-line in the case. Pumped storage hydro resources were modeled in pumping mode.

Wind generation was modeled at 40 percent of nameplate rating and ramped up to 80 percent if selected by the test criteria:

- PJM existing wind generation: approximately 3,800 MW
- PJM FSA and ISA wind generation: approximately 2,300 MW
- Midwest ISO existing wind generation: approximately 6,000 MW

Existing Midwest ISO wind generation was modeled online at 80 percent of unit nameplate rating. Midwest ISO wind generation was uniformly sunk to all online Midwest ISO generation.
### Preliminary Sensitivity Analysis Results

A number of new discrete elements were overloaded in this analysis that are not overloaded in the 2014 Summer Peak RTEP case, as shown in Table 15.3.

A number of the identified overloads can be attributed to running the generator deliverability test on a light load case with the modified base dispatch. Many can also be attributed to the ramping impact of the wind generation.

PJM will continue to work with stakeholders in 2011 to refine and develop further RTEP process light load criteria.

#### Table 15.3: PJM Light Load Sensitivity Analysis: Overloaded Elements

<table>
<thead>
<tr>
<th>Area</th>
<th>Voltage</th>
<th>0% / 100%</th>
<th>0% / 80%</th>
<th>3% / 80%</th>
<th>5% / 80%</th>
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</thead>
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<tr>
<td>AEP</td>
<td>345/500</td>
<td>2</td>
<td>2</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>138/138</td>
<td>3</td>
<td>2</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>APS</td>
<td>138/138</td>
<td>7</td>
<td>6</td>
<td>5</td>
<td>5</td>
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<tr>
<td></td>
<td>345/345</td>
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<td>1</td>
</tr>
<tr>
<td></td>
<td>345/138</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>138/345</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>ComEd</td>
<td>138/138</td>
<td>30</td>
<td>15</td>
<td>9</td>
<td>9</td>
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<tr>
<td>Dominion</td>
<td>500/500</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>138/115</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>PECO</td>
<td>500/230</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td></td>
<td>230/230</td>
<td>1</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>138/138</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
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<tr>
<td>PECO/BGE TIE</td>
<td>230/230</td>
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<td>PENELEC</td>
<td>115/115</td>
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<td></td>
<td>1/230</td>
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<td>PL</td>
<td>230/230</td>
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<td>0</td>
<td>0</td>
</tr>
<tr>
<td>PL/BGE TIE</td>
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<td>1</td>
<td>1</td>
<td>0</td>
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</tr>
<tr>
<td></td>
<td>115/115</td>
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<tr>
<td>PL/UGI TIE</td>
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<td>1</td>
<td>1</td>
<td>1</td>
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<tr>
<td>PSEG</td>
<td>345/345</td>
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<td>2</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>230/230</td>
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<td>1</td>
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<td>1</td>
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<tr>
<td>Total</td>
<td></td>
<td>69</td>
<td>48</td>
<td>30</td>
<td>30</td>
</tr>
</tbody>
</table>
15.7: 2011 RTEP – PATH Line Suspension

Preliminary 2011 PJM RTEP process analysis suggests that the need for the PATH line has moved several years into the future beyond 2015.

The outlook for a slower economic recovery – reflected in the reduced load growth rates in PJM’s January 2011 published forecast – has led the PJM Board to direct transmission owners to suspend efforts on the PATH line pending a more complete analysis in the 2011 RTEP. Section 5 of this report discusses the PATH suspension.

Through the current Regional Transmission Expansion Plan (RTEP), PJM has identified – over a 15-year horizon – when the forecasted power flows in specific areas of the grid would violate national and local standards for reliable operation of the bulk electric system. This process necessarily requires estimating the future demand for electricity, as well as analyzing the committed resources that serve that demand, in order to determine when and where future power flows will exceed the thermal and voltage limitations of existing transmission facilities.

While any estimate of future economic activity and its effect on both demand and supply is inherently uncertain, PJM generally has found, based on its experience, that the magnitude of uncertainty was limited and that FERC-approved “bright line” tests such as are currently used in the RTEP process could reasonably define the expected date of future reliability violations, thereby allowing PJM to plan for new transmission facilities.

Greater Uncertainties

Recent dramatic swings in economic forecasts and evolving public policies (particularly with respect to renewable energy) are adding greater uncertainty to PJM planning studies. Uncertainty about generation retirements, particularly in response to potential changes in environmental regulations, may also be diminishing the robustness of current planning criteria.

Moreover, a set of new and greater uncertainties – not just with load growth estimates but also other key indicators relevant to planning studies – are complicating the analysis of future reliability needs. In particular, the growth of Demand Resource programs can contribute to lower expectations for future peak demand, thereby extending the time period when transmission upgrades are needed.

2011 RTEP Process

Based on analysis conducted in 2007, the PJM Board approved the PATH line. Subsequent analysis extended the “required in-service date” by which the line was needed to resolve reliability violations to 2015.

As part of the 2011 RTEP, and in response to a request by a Virginia Hearing Examiner, PJM is conducting a series of analyses using the most current economic forecasts and Demand Resource commitments, as well as potential new generation resources. Preliminary analysis has revealed that expected reliability violations driving the need for PATH have moved several years into the future.

Based on these latest results, the PJM Board decided to suspend the PATH project while PJM conducts more rigorous analysis of the potential need for PATH. This action, however, does not, at this time, constitute a directive by PJM to the sponsoring Transmission Owners to cancel or abandon the PATH project. The PJM Board’s action affects only PATH.

PJM will complete this more rigorous analysis of the PATH project and other transmission requirements and then report the results to stakeholders when it is available. The Board will review this comprehensive analysis as part of its consideration of the 2011 Regional Transmission Expansion Plan.

Managing Uncertainties in Transmission Planning

Through the Regional Planning Process Task Force and other forums, PJM stakeholders are evaluating the current planning criteria and considering better ways to manage all factors driving transmission planning upgrades. The PJM Board strongly supports this effort and has asked PJM members to bring forth recommendations by this fall so that PJM might make appropriate filings and then enact improvements in the planning process at the beginning of 2012.