

Section 9: Addressing Long-Term Challenges



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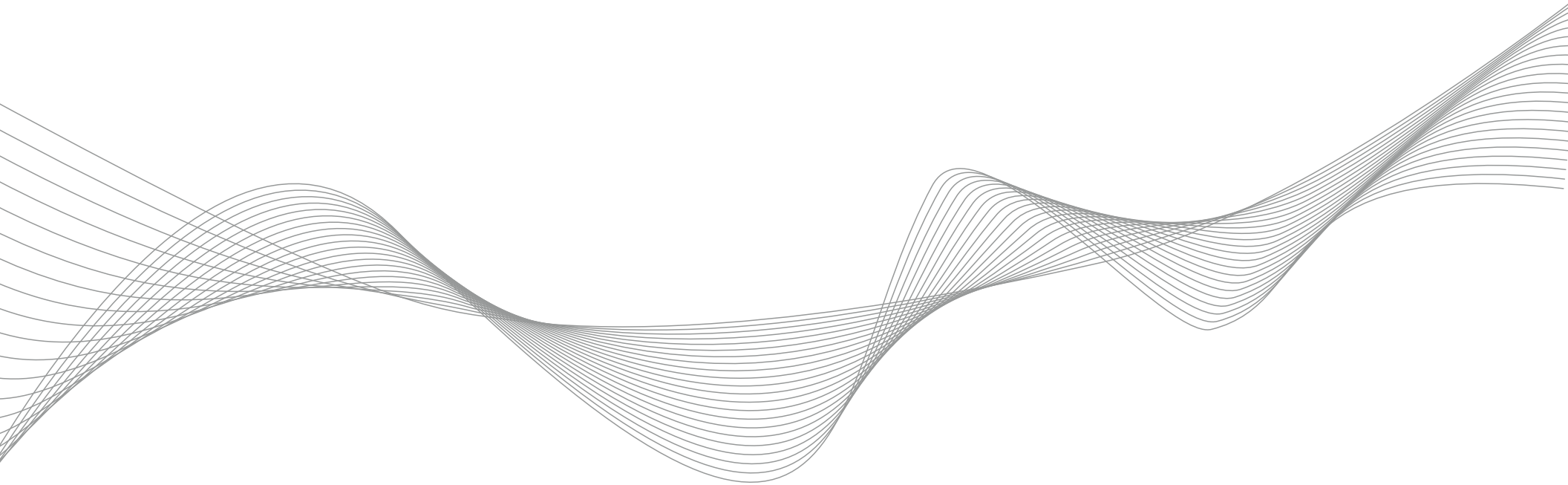
Since its 1997 inception, PJM’s RTEP Process has adapted to expanding geographic markets, new and modified market offerings and other growing external and internal influences. 2008 has been no exception. **Section 9** discusses emerging RTEP trends based on initiatives within the RTO-stakeholder sphere itself as well from a number of external factors driving RTEP change, depicted in Figure 9.1. Some developments are new. Others continue to evolve in light of ongoing activity.

Section 9.1 Presents updated and new material regarding RTEP process developments that are driven by internal PJM and stakeholder initiatives and other factors. A perspective on recent load forecast trends and changes is included. Significant process improvements continue in 2008 and expand upon the efforts begun in 2007. Process enhancements address market efficiency planning procedures, cost allocation procedures and queue request process modifications to address queue back-logs.

Section 9.2 summarizes external factors unfolding within the industry that are driving the need for RTEP process response as well: public policy considerations such as state renewable generation portfolio requirements, NERC and RFC initiatives addressing reliability criteria and compliance and Interregional Planning.

Figure 9.1: Long-Term Challenges







9.1: RTEP Process Developments: PJM RTO / Stakeholder Sphere

9.1.1 – Load Forecasting Developments

PJM's RTEP process culminates in regional transmission expansion plans to address identified NERC reliability criteria violations, market efficiency and other issues. A fundamental input to this work is the forecast of system power requirements. PJM's 2013 baseline analysis employed the January 2008 Load Forecast Report, as updated in May 2008. This report is available on PJM's Web site via the following URL: <http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx>.

Impact of Economic Conditions

Since evolving economic conditions are at the forefront of current events and likely the minds of readers of this report, it is important to make clear how PJM is accounting for these events in the 2009 RTEP analyses that are about to begin. The downturn is now predicted to have effects for the next two years. The 2009 Load Forecast Report, instead of using an October econometric report, relied on a December revision to capture the latest possible nuance in today's rapidly changing economic landscape. The 2009 forecast reflects a significant dip in near term load forecasts with smaller but persistent deficits throughout the entire 15-year planning horizon.

PJM's 2009 RTEP analyses will incorporate this most recent forecast information in retool analyses of the 2010, 2011, 2012 and 2013 baseline analyses. This work will refresh the approved plans for these years. Likewise, the 2009 forecast will also factor into 2014 baseline analyses as well.

The significance of the updated load forecasts coupled with the scope of the major backbone facilities identified in each year 2010 through 2013 suggests that PJM Planning staff address these retool analyses first, then a 2014 baseline thereafter. PJM is doing just that in its 2009 RTEP process.

9.1.2 – Demand Side Management Initiatives

Load Management

In 2008, PJM's stakeholders endorsed load forecast procedure refinements proposed by PJM. These included revised Load Management (LM) processes to account more fully for comparable treatment of responsive load solutions in the RTEP. Beginning with the 2009 load report, LM will be replaced by two Load Management components: Demand Resources (DR) and Interruptible Load for Reliability (ILR.) DR will be determined from the three-year forward commitment RPM auctions. The forecast will use the value cleared in the last auction and hold it constant through the forecast horizon. ILR will be based on the historical average five-year response per PJM certification in PJM markets.

Energy Efficiency (EE)

In addition, PJM forecast projections, now include the impact of EE programs based on the amount cleared in RPM auctions. This represents the acceleration of EE otherwise delayed until a later year or new EE in addition to what may be imbedded in load. These enhancements will further bolster the comparable treatment of non-traditional resource alternatives in PJM's RTEP.

9.1.3 – Cost Allocation Procedures

PJM cost allocation for RTEP upgrades follows the provisions of PJM’s Operating Agreement, Schedule 6 (Operating Agreement) and the PJM Open Access Transmission Tariff, Schedule 12 (OATT.) FERC action in 2008 continued to clarify several outstanding issues.

Allocation of Baseline Backbone Transmission Expansion Costs – Review of 2007

The FERC issued an order in April 2007 governing the allocation of new transmission in PJM. In summary, the FERC ruled on the following:

- The costs of new facilities operating at 500 kilovolts (kV) or above that are planned through PJM’s Regional Transmission Expansion Planning (RTEP) process will be shared across the whole region. This affects both reliability and economic projects. The FERC stated that the broad, regional benefits of such projects justified the sharing of costs region-wide.
- The costs of new RTEP facilities below 500 kV will continue to be funded under PJM’s existing approach, “beneficiary pays,” in which those benefiting from a new project must pay its costs.
- The costs of existing transmission facilities, as well as supplemental upgrades initiated by PJM’s Transmission Owners, will continue to be allocated on a zonal basis. The FERC found that this approach “reflects the prior investment decisions of the individual transmission owners,” adding that the facilities were built primarily “to support load within the individual transmission owners’ zones and continue to serve those loads.”

On September 14, 2007, PJM filed a Settlement Agreement and Offer of Partial Settlement related to the allocation of costs for below 500 kV facilities. That Settlement proposed resolution of all issues except for matters regarding assignment of cost responsibility to merchant transmission facilities.

2008 Progress on Baseline Backbone Cost Allocation

The Commission approved the Partial Settlement (applicable to facilities below 500 kV) in orders issued on July 29 and October 15, 2008. The Commission directed PJM to apply its DFAX method to reliability-based facilities below 500 kV, with the exception of allocations to merchant transmission facilities. DFAX (short-hand for “distribution factor”) is an industry concept which refers to the power flow impact on a monitored facility for an incremental change in system flow caused by a transmission outage or imposed transfer. DFAX is typically expressed in terms of a percentage of the transfer or flow on the outage facility that appears on the monitored facility.

Cost allocation for upgrades that are economic advancements of RTEP reliability upgrades will be allocated by the DFAX method except if the load zone LMP benefits differ more than 10 percent from the DFAX method. In this exception, the allocation will be based on the load zone LMP benefits for the period of time represented by the acceleration of the reliability project. A cost allocation method for new economic efficiency upgrades below 500 kV that are not previously identified as reliability upgrades is expected to be filed in the later part of 2009. The Settlement applies to assignments of cost responsibility that were pending in Docket No. ER06-456, et al. and also to all facilities approved by the PJM Board after June 1, 2007.

9.1.4 – Interconnection Request Process Improvements

PJM's robust capacity and energy markets continue to attract significant volumes of generation interconnection requests, constituting a significant driver of regional transmission expansion needs.

The increases in the volume of interconnection requests since the beginning of Queue M on February 1, 2004 has driven a proportionate increase in the number of interconnection studies required. These studies ensure the means for delivering the output of interconnected generation. PJM's generator interconnection process continues to ensure that new capacity resources satisfy load serving entity requirements to meet their obligations reliably.

Coupled with merchant transmission interconnection requests, long-term firm transmission service requests and Auction Revenue Right (ARR) requests, PJM's generation interconnection request study volume has experienced a backlog. PJM, in collaboration with stakeholders, completed process changes in 2008 to alleviate this current backlog and to create a more efficient interconnection study process moving forward as well.

Managing Queue Volume

As part of a package of process improvements approved by the FERC last year, beginning with Queue U1 on February 1, 2008, PJM migrated from two queues every twelve months to four queues every twelve months. The objective of this change is to encourage distribution of queue requests throughout the year. Each request requires first, an initial scoping meeting followed by ongoing coordination and evaluation by PJM planning staff.

Figure 9.2: Generation Interconnection Request Queue Volume

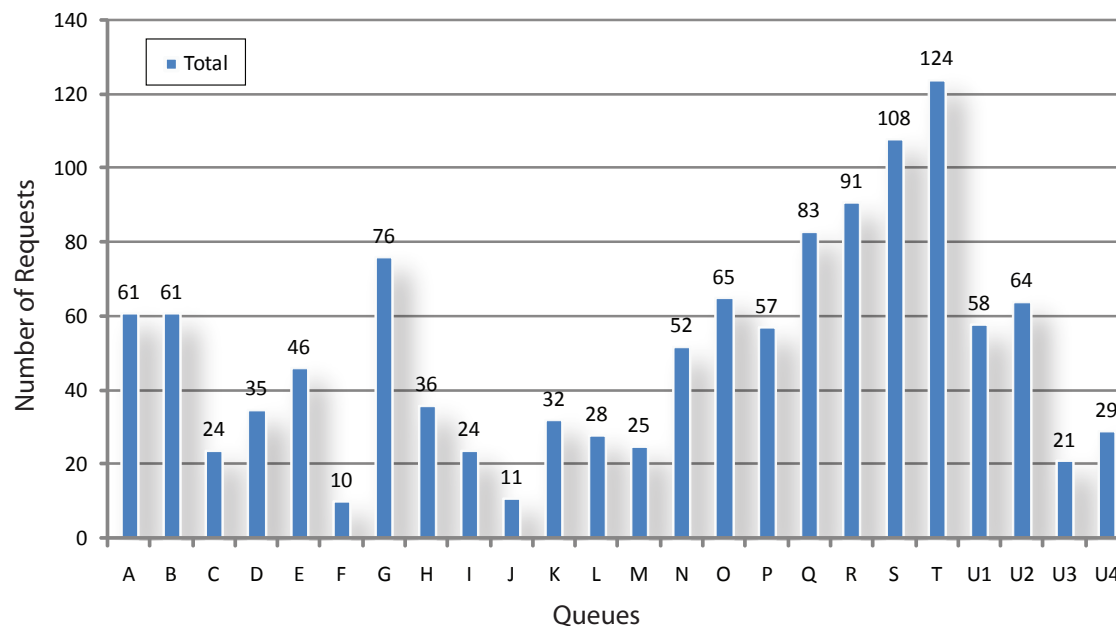


Figure 9.2 illustrates historical volumes for generation interconnection request queue activity. The figure also illustrates PJM's initial experience with quarterly queues, as depicted by the volumes for queues U-1 through U-4, whose windows – for the sake of reference – are summarized below:

- U1: February 1, 2008 – April 30, 2008
- U2: May 1, 2008 – July 31, 2008
- U3: August 1, 2008 – October 30, 2008
- U4: November 1, 2008 – January 31, 2009

This change to quarterly queues should mitigate the impact of the large influx of projects just before each queue closes, the most recent example of which is demonstrated in Queue T as shown in Table 9.1. Queue T – encompassing a six month period – witnessed 124 generation interconnection

requests, 37 of which were submitted the last week of the queue. In contrast, the interconnection requests in Queues U1 and U2 were spread over a six month period.

This begins to illustrate that the queue structure modification can enable more efficient and responsive management of queue volume. The quarterly queues will provide more frequent opportunities for projects to initiate the study process. This is expected to alleviate some of the last minute rush for queue positions near the close of each queue helping to ease the resource strain caused by coincident study due dates and associated peaks of study activity.

Queues U3 and U4 witnessed significant interconnection requests reductions overall, 21 and 29 total requests respectively. PJM believes this is the result of a number of factors including U.S. economic conditions as well as a changing political and regulatory environment.

PJM recognizes that the transition to quarterly queues is only one step in a process that continues in an ongoing effort to improve timely completion of interconnection evaluations and agreements.

Interconnection Requests Remain Varied

Overall, PJM’s RTEP process not only includes queued requests for generation interconnection but also encompasses queued requests for merchant transmission interconnection, long-term firm transmission service and upgrade Auction Revenue Right upgrade requests. Recent queue activity is shown in Table 9.2.

All these types of requests require coordinated evaluation by PJM planning staff. Even more so, requests for unit deactivation and conversion of expiring generator agreements to Interconnection Service Agreements also add to PJM resource requirements for coordination and study.

Table 9.1: Request Volume During Last Week of Queue

Number of Days Remaining in Queue	Queue T	Queue U1	Queue U2	Queue U3	Queue U4
0	25	3	14	3	0
1	6	4	10	1	2
2	1	0	0	2	0
3	4	0	0	0	1
4	0	0	0	0	0
5	0	0	0	0	0
6	1	0	2	0	0

Table 9.2: Queued Requests for RTEP Analysis

Request Type	Queue Volume				
	Queue T	Queue U1	Queue U2	Queue U3	Queue U4
Generation Interconnection	124	58	64	21	29
Merchant Transmission	4	0	9	0	2
Long-term Firm Transmission Service	45	38	22	7	8
Auction Revenue Rights (ARRs)	3	0	0	0	0
Total	176	96	95	28	39

Addressing Study Backlog

Throughout 2008, PJM actively engaged stakeholders in discussion of process enhancements to address the backlog of projects in the queues with pending interconnection requests yet to be studied. Attention has focused on means to ensure that projects embarking on the PJM study process are ready to commit resources to project development and also on methods to facilitate the processing of projects once they enter the queue.

Related Tariff amendments were approved by PJM’s Members Committee in June 2008. These proposed amendments are expected to provide significant improvement to the current process. On

August 19, 2008, FERC accepted the revisions for filing, effective. Modifications to interconnection procedures included the following:

- i. cluster studying of queued projects;
- ii. revised Feasibility Study deposit structure;
- iii. studying primary and secondary points of interconnection at the Feasibility Study Phase;
- iv. cost allocation between queues; and
- v. scheduling project scoping meetings.

These changes became effective August 1, 2008.

Stream-lined Calculation of Project Related Cost Allocation

Local Upgrade and Network Upgrade costs less than \$5 million will be allocated to all projects that contribute to the reliability criteria violations, regardless of queue position, pursuant to each project's megawatt contribution to the need for each identified upgrade. Upgrades costing \$5 million or greater will be allocated to interconnection requests in queue order rather than on a more socialized basis. The result is no change to the cost allocation methodology for projects with upgrades costing \$5 million or more. This change to cluster allocation of project costs for upgrades less than \$5 million will enable more expedient determination of initial cost allocations and greatly facilitate any required retool analyses to determine revised cost allocations in light of queued interconnection request withdrawals.

Effective August 1, 2008, this revised process was initially applied to the Queue U2 which closed on July 31, 2008. In addition, PJM is applying its DFAX analysis method to allocate costs to queued backlogged projects as well. August 1, 2008 also marked the effective date for revised tariff provisions for allocating costs across queues

9.1.5 – Additional Queue Process Reforms

Throughout 2008, PJM and its stakeholders addressed a number of additional queue process reforms, largely the result of ongoing dialogue with the PJM Regional Planning Process Working Group (RPPWG). The package of changes addressed the entire queue process trajectory as summarized in Table 9.3. Some required only manual changes while others required full FERC filings to amend OATT provisions governing the interconnection process. Additional changes are also under

development for consideration by the PJM Members Committee in 2009.

A few of the key changes in 2008 are discussed further below.

Study deposits

Submitting an interconnection request requires a project developer to post a deposit fee for initial phases of study. These deposits have been increased to encourage early entry into the queue and to help ensure projects entering the queue are prepared to commit resources to the project. Thus deposit requirements at the feasibility study stage are increased with higher amounts required as the queue deadline approaches. Stakeholders have also endorsed increases in the impact study deposits based on the same reasoning. This revised system impact study deposit structure will be filed early in 2009. Revised study fee structures can be found in PJM Manual 14-A, "Generation and Transmission Interconnection Process," available on PJM's Web site via the following URL: <http://www.pjm.com/documents/manuals.aspx>.

Primary and Secondary Points of Interconnection (POI)

PJM anticipates additional interconnection study process efficiency the result of a change in the method by which PJM studies a customer's primary and secondary Points of Interconnection (POI). PJM dialogue with stakeholders revealed that the value to the customer of a second comprehensive study of a secondary POI was outweighed by the concomitant additional complexity and delay.

Previously, if the interconnection customer chose two POIs, PJM was required to conduct two simultaneous sets of studies for each of the two interconnection points. In addition, the next queued project in the same area had to be studied twice, once for each POI choice of the previous project. The distinct study combinations increased exponentially if additional queue projects were also in the vicinity. The study work for maintaining two POI choices quickly becomes unmanageable.

Consequently PJM, in concert with its stakeholders, has changed the process to study, firstly, all projects in a queue based on their primary POI choice. Subsequently, PJM will study desired second POI choices as independent project by project sensitivity studies. These studies will provide sensitivities of line loadings, without cost estimate detail. This is expected to significantly facilitate the flow of queue studies. This change became effective August 1, 2008.

Scheduling of the scoping meeting

Upon entering a queue and requesting a feasibility study, the interconnection customer and PJM must schedule a project scoping meeting at which Points of Interconnection and other study details are mutually agreed. In keeping with the objective of encouraging early queue entry, PJM has established progressively shorter deadlines for this milestone. As the queue progresses, queue entrants in the first month have 45 days to hold this meeting. Entrants in the second and third months have 30 and 20 days respectively. This change also became effective August 1, 2008

Table 9.3: PJM Queue Process Improvements

Queue Process Improvement	Process Improvement Description	Formalization of Change	Effective Queue
3 Month Queues	Four queues a year, three month Feasibility Study period.	Tariff change	Queue U1
Feasibility Deposit Changes	Deposit increases each month during the queue. Includes a non-refundable element and a \$/MW deposit fee structure	Tariff change	Queue U3
Scoping Meeting Timelines	Timeframe for holding scoping meeting linked to when the interconnection request was submitted during the queue. PJM to provide 3 suggested scoping meeting dates. Customer can waive meeting upon mutual agreement of the parties.	Tariff change	Queue U3
Optional Interconnection Points at Feasibility	Interconnection Customer can request study of primary and secondary interconnection points in lieu of two proposed interconnection points and two separate sets of studies.	Tariff change	Queue U3
Feasibility and Impact Data Submittal	Final data must be submitted before accepting agreement.	Manual change	All queues
Cluster Study and Case Lockdown	Do not restudy in the middle of the queue.	Manual change	All queues
Cost Allocation Methodology	1. Cost allocation among cluster based on \$5 million threshold. 2. Inter-queue cost allocation not permitted for projects <\$5 million	Tariff change	Queue U2
Capacity Interconnection Rights	1. Clarify commencement of testing period and clarify terminology; 2. Clarify loss of CIR's upon deactivation	Tariff change	All queues
Commercial Probability Method	Apply commercial probability at Feasibility and System Impact Study	Manual change	Queue U3
System Impact Study Deposit Change	Increased deposit fees with a non-refundable and refundable components. Includes a \$/MW amount for projects >20 MWs. Added clarifying language regarding return of refundable and non-refundable components.	Tariff change	Queue V2 (Opens May 1, 2009)
Wind Site Control	10 acres/MW minimum (3 acres/MW on ridge), or site plan	Manual change	Queue V1 (Opens Feb. 1, 2009)
Generator Site Control of Interconnection Facilities	At facilities study phase, may be required to show have site control if Option to Build. Will be included as milestone in Facilities Study Agreement where necessary.	Tariff change	Queue V1 (Opens May1, 2009)
Milestone Requirements Related to Merchant Transmission Projects	Require queue position in neighboring control area within 30 days of PJM Interconnection Request	Tariff change	Queue V2
Invoice Payment Proposal	Must be current with invoices before moving to next phase of interconnection process. Failure to pay deems request withdrawn. New requests considered deficient until all past due is paid. If not cured, also deemed withdrawn.	Tariff change	Effective for all queue projects when approved
Facilities Study / ISA Proposal	1. Facility Study deposit changes for requests under 20 MW. 2. ISA - ability to request additional milestone to receive ISA and post security within 120 days with a minimum deposit of \$200K.	Tariff change	Effective for all queue projects when approved

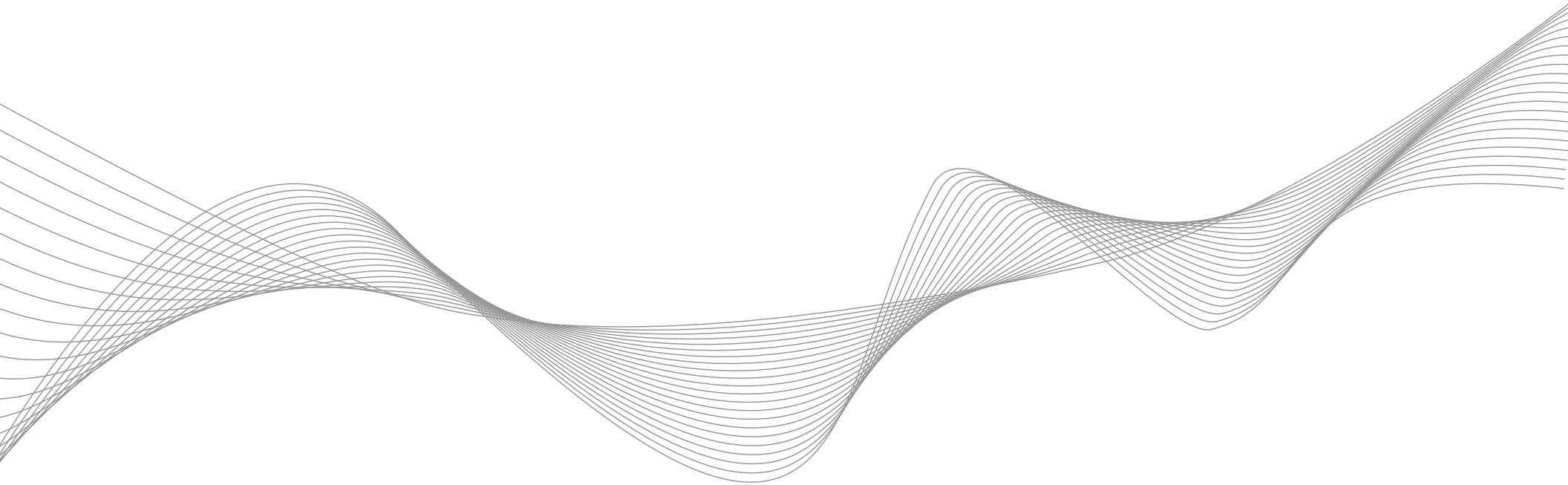
9.1.6 – RTEP Market Efficiency Planning

PJM's RTEP process includes analysis of the economic efficiency of transmission enhancements. In 2008, the FERC accepted PJM's "bright line" for recommending an upgrade on economic grounds, (subject to some additional clarification by PJM). The outcome is an approved "bright-line" test that is applied to the following:

1. RTEP reliability projects to see if they should be considered for advancement due to economic benefits.
2. New proposals that may produce economic benefits.

The Bright-Line test specifies that a proposed solution's savings is the sum of the weighted production cost of energy and capacity plus the weighted load cost of energy and capacity (weighted 70% production cost and 30% load cost of energy) must exceed its projected revenue requirements on a 15 year present worth basis, by at least 25%. Projects satisfying this bright-line formula will be presumptively included in PJM's RTEP.

PJM clarified its bright-line formula calculates load payments for energy as net of the change in the value of transmission rights. In addition the stream of calculated project costs and benefits is discounted to a common year using a discount rate that blends all PJM Transmission Owner's levelized carrying charge rates for comparable transmission projects. PJM further clarified that the cost to accelerate reliability projects will be calculated as the estimated change in annual revenue requirement resulting from the acceleration of the planned reliability-based enhancement or expansion, taking account of all of the costs incurred that would not have been incurred but for the acceleration of the planned reliability-based enhancement or expansion (These clarifications were accepted by the FERC in early 2009).





9.2: External Sphere RTEP Planning Drivers

PJM's RTEP process must remain flexible to address the many external influences that affect all aspects of planning activities, often increasing the volume of work required. This section discusses several.

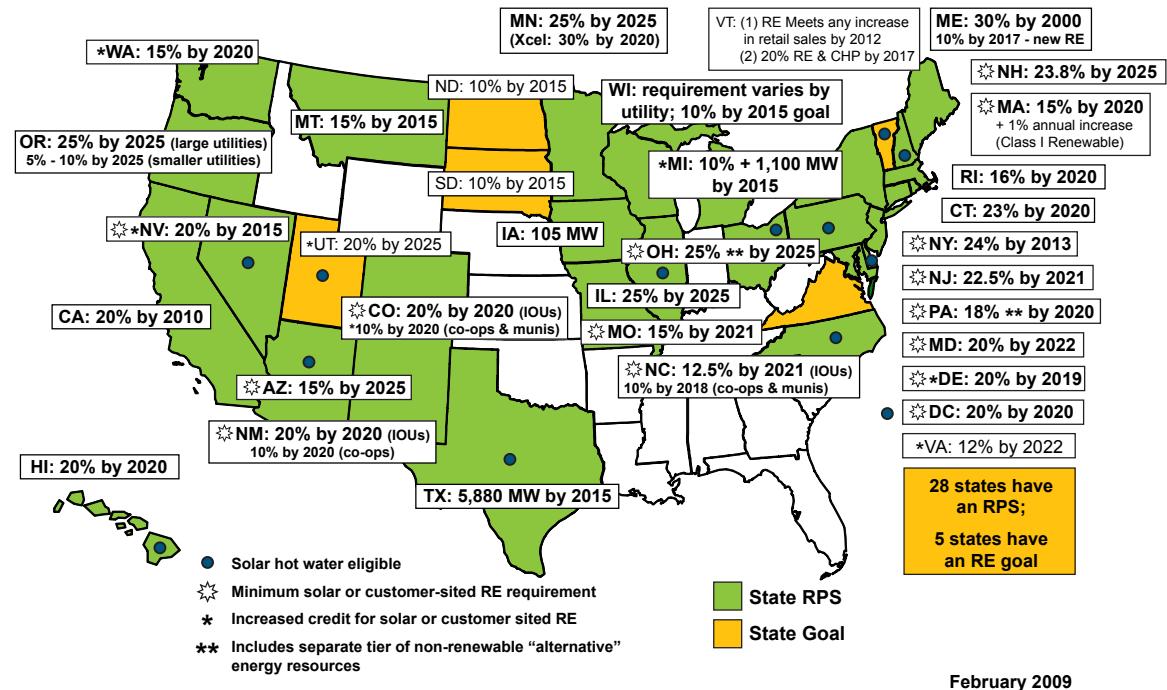
9.2.1 – Public Policy and Industry Response

National concern for developing adequate supplies of electric power in an environmentally sound manner has led to state consideration of Renewable Portfolio Standards (RPS). One convenient source for more information on renewable energy standards can be found in the Database of State Incentives for Renewables & Efficiency, which is an ongoing project of the North Carolina Solar Center and the Interstate Renewable Energy Council (IREC) funded by the U.S. Department of Energy (<http://www.dsireusa.org/>).

Figure 9.3 shows the current status of RPS initiatives across the United States. Wind resources provide one significant option to satisfy RPS requirements. Such resources, however, are often located in areas that pose challenges regarding transmission access to the load centers where their output is most needed. Continued state initiatives based on such standards could lead to substantial development of wind resources in areas best suited to optimize this technology. Public policy initiatives possibly directed toward electric grid infrastructure development could impact future RTEP planning as well. Interregional studies such as current joint

Figure 9.3: Status of RPS Initiatives Across the U.S.

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DSIRE: www.dsireusa.org

efforts like the JCSP and EWITS, discussed below, contribute to early formation of PJM's planning preparation.

Reliability Portfolio Standards

PJM's footprint encompasses 13 states and the District of Columbia (DC.) Eight states and DC have enacted legislation that sets Renewable Portfolio Standards (RPS). These same jurisdictions have also enacted or are working on Energy Efficiency

legislation. The purpose of RPS is to foster development of cost effective demand and markets for renewable energy. These standards and policy incentives are expected to result in significant contributions of clean, environmentally friendly resource development to serve PJM load. Energy Efficiency standards promote moderation in the growth of peak demand and energy. PJM supports these efforts and is closely monitoring developments to anticipate complementary

modifications as may be desirable to markets and transmission planning.

While wind and solar options lead the list of RPS portfolio options, the complete list is extensive and is included in information accessible by following the links below. For example, other options include biomass, fuel cells, hydroelectric and waste coal. Also, notable characteristics of the current rules require that compliance in Pennsylvania and Virginia be satisfied by sources within the RTO, while North Carolina requires 75% from in-state resources and Ohio requires 50% from in-state sources. Additionally, many programs include credit multipliers for specified options and alternative compliance payments. Table 9.4 and Table 9.5 summarize the current status of Energy Efficiency standards and RPS initiatives within PJM.

Additional information and detail regarding the ongoing evolution of the RPS and Energy Efficiency efforts is available online:

- EPA: http://www.epa.gov/chp/state-policy/renewable_fs.html
- EERE: http://apps1.eere.energy.gov/states/alternatives/resources_by_state.cfm
- DSIRE USA: <http://www.dsireusa.org/Index.cfm?EE=0&RE=1>

Table 9.4: Energy Efficiency and Demand Response in PJM Jurisdictions (as of 1/30/09)

State	Status of Program Development	Energy Reduction Goal	Year Reductions Are To Begin	Year Reduction Goal Is To Be Reached
Delaware	Status: Legislation in development. 5 year Energy Plan to be presented to Governor and staff in finalized form by February 2009	State Energy plan calls for reduction years 2008 through 2013 - Once approved, outline of programs and initiatives will be available to publish	2009	2013
District of Columbia	FY 2009 PSC decision re PEPCO's proposed energy efficiency programs. PSC also to revise REPS rules to address the 2008 Act's higher standards and accelerated schedule than in the 2005 Act.**	DR: Five Demand Side Mngt programs have been provisionally approved for Residential and Non-Residential EE: Begin implementing the clean and affordable energy (CAE) Act of 2008, and to expand the Commission's public awareness programs	2009	2012
Illinois	Status: Legislation enacted DR: SB 1592 enacted in 2007. EE: SB 1592 Enacted in 2007	DR: reduce peak demand by 0.1% over the prior year for eligible retail customers. EE: energy savings goals of 0.2% each year until 2015. 2015 - the annual energy savings is to be 2% for that year and every year thereafter.	DR: 2008 EE: 2008	DR: 2018 EE: 2015
Maryland	Status: Legislation enacted. Laws passed 2008	DR: 5% by the end of 2011, 10% by the end of 2013, and 15% by the end of 2015 over 2007. EE: least 5% by end of 2011 & 10% by the end of 2015 over 2007.	2008	2015
Michigan	Status: Legislation enacted - 2008 PA 295 was passed that established renewable portfolio standards (10% by 2015) and required a portion of the renewable resources to be sited in the State.	A goal to reduce energy use in the state by 5% by 2015 and reduce energy use by state government by 20% by 2015		
New Jersey	Status: Legislation In Development: Energy Master Plan released on October 22, 2008	DR- 5700 MW 2010 EE - 20% reduction 2010 (2200 thru DR programs, 3500 thru EE)	EE - 2010 thru 2020 DR - 2010 thru 2020	2020
North Carolina	Status: Legislation enacted. Law Passed 2007 and NCUC issued Order Adopting Final Rules in 2008	IOUs - 12.5% of energy needs through renewable energy resources or energy efficiency measures. Rural electric cooperatives and municipal electric suppliers subject to 0% REPS.	2007	2021
Ohio	Status: Legislation enacted 5/1/08: addresses the expiration of rate caps at the end of 2008 and requirements to cut load via energy efficiency and demand response.	2008 Legislation prescribes energy savings and peak demand reduction requirements through 2025; sets yearly benchmarks, and commission enforcement of compliance	2009	2025
Pennsylvania	HB 2200 signed into law on Oct. 15, 2008, creating Act 129. It mandates EE and Peak Demand Reductions.	EE goal of 1% by May 31, 2011 and 3% by May 31, 2013. Peak Demand Reduction of 4.5% is required by May 31, 2013. EDC's are subject to penalties of up to \$20 million for non-compliance.	2011	2013
Virginia	Status: Legislation enacted. Energy Plan Issued by Governor Sept 2007.	2022 Goal to reduce usage by 10% over 2006 through conservation and efficiency. Reaching 10% defers approx. 3,900 MW of new capacity by 2022.	2007	2022

Table 9.5: RPS Initiatives in PJM Jurisdictions (2/15/09)

	DC	DE	IL	MD	MI	NC	NJ	OH	PA	VA
Regulation or Legislation	Bill 15-747 (effective 4/1/2005) Bill 17-0492 (effective 10/6/2008)	Senate Bill 74 (2005) and Senate Bill 19 (2007) Senate Bill 328 enacted 6/28/2008	Public Act 095-0481, the Illinois Power Agency Act of August 2007,	HB 1308 / SB 869 (2004), SB 595 (2007) added solar requirement, HB 375 (2008) doubled Tier 1 requirement.	Public Act 295, (October 6, 2008)	SB 3 (August 2007)	N.J.A.C 14-4-8 - NJ Renewable Portfolio Standards Rules (effective April 19, 2004)	SB 221 (May 2008)	Senate Bill 1030 (Printer's No 1973), Act 213, HB 1203 (2007), Act 35	SB 1416 (4/2007) SB 718 (3/2008)
Geographic Eligibility	Source must be: (1) located in the PJM Region or in a state that is adjacent to the PJM Region; or (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.	Eligible Energy Resources" include energy resources located within or imported into the PJM region.	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.	Source must be: (1) located in the PJM Region or in a state that is adjacent to the PJM Region; or (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.	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.	75% from in-state resources Out-of-state renewables up to 25% of standard for hydro up to 10 MW or renewables placed in service on or after January 1, 2007.	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.	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.	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.	Electricity must be generated or purchased in Virginia or in the interconnection region of the regional transmission entity.
Alternative Compliance Payment (ACP)	Tier 1 - \$50/MWh Tier 2 - \$10/MWh Solar - \$300/MWh in 2007 and 2008, \$500/MWh in 2009 thru 2014, declining thereafter.	\$25 for 1st deficient year. \$50 for 2nd deficient year. \$80 for subsequent years. Solar ACP is \$250, \$300, and \$350, respectively.	None. Resources must be "cost-effective."	Tier 1 - \$40 / MWh Tier 2 - \$15 / MWh Solar - \$450 / MWh in 2008, \$400 / MWh in 2009, declining to \$50 / MWh in 2023	Not applicable for the Renewable Energy Requirement.	None. Recoverable costs are capped.	Class I & II (ACP) - \$50/MWh Solar (SACP) - \$450/MWh initially. For 2008/2009 it is \$711/MWh, declining over eight years to \$594 in 2015/16.	REC - \$45/MWh Solar - \$450/MWh in 2009, \$400 2010 and 2011, reduced by \$50 every two years thereafter.	Tier I (except solar) and Tier II - \$45 / MWh Solar - 200% of the average market value for solar RECs sold in the RTO.	None. Voluntary goal.
Credit Multipliers	a). 120% credits for wind or solar Energy before 12/31/2006 b). 110% credits for wind or solar Energy between 1/1/2007 and 12/31/2009 c). 110% credits for Methane from landfill or sewage treatment until 12/31/2009	a). 300% for in-state solar renewable fuel cells before 12/31/2014. b). 150% credit for wind energy in-state before 12/31/2012. c). 350% credit for wind off the DE coast before 5/31/2017.	No.	After gen built after 1/1/04: 120% for wind before 12/31/2005; 110% for wind between 1/1/2006 and 12/31/2008; 110% for Methane from landfill or sewage treatment until 12/31/2008	• Solar receives an additional 2 credits per MWh • Lesser bonuses awarded for on-peak production, storage, and using in-state labor or equipment	No.	No.	No	No	Wind and solar power receive a double credit toward RPS goals.
RPS - Year	2020	2019 / 2020	2025 / 2026	2022	2015	2021	2020/2021	2024	2020 / 2021	2022
RPS - Percentage	20% Total	Tier 1: 8.0%. Total: 18.0 %	25%	Total: 20%	10 %	12. %	Class I: 20% Total: 22.5%	12.5	Tier I: 8.0 % Total: 18.0%	12 %

9.2.2 – NERC Related Activities

Transmission Planning Standards

North American Electric Reliability Corporation (NERC) governs standards development and compliance. More information regarding the details and status of all of NERC's standards development work can be found at www.NERC.com.

The planning standards currently codified as TPL-001 through TPL-004 contain analysis requirements for assessing bulk power system performance under normal, contingency and extreme conditions. These standards are scheduled to be replaced by a single standard, TPL-001-1, which by current timelines, would become effective for PJM planning in 2010. One principal objective of the revisions is to clarify the standards and add detail to establish a higher degree of consistency among the planning analyses currently performed throughout North America.

PJM does not expect major changes to its RTEP process as a result of the standard changes planned by NERC. However, PJM staff resources required to coordinate the necessary analysis and documentation to demonstrate PJM compliance is expected to increase significantly in 2009. As with all such related activities, the PJM Planning Committee is kept apprised of all changes.

Audit Compliance

The Federal Energy Regulatory Commission (FERC) has designated NERC as the Electric Reliability Organization (ERO) responsible for establishing and enforcing reliability standards for the bulk electric system. NERC has delegated responsibility for the implementation of the Compliance Management and Enforcement Program to eight Regional Entities. PJM operates its system in areas that are part of two Regional Entities, the SERC Reliability Corporation and the ReliabilityFirst Corporation. ReliabilityFirst conducted the first compliance audit of PJM in May 2007. This audit included an extensive review of PJM's RTEP process and documentation, as well as other functional areas of PJM. In May 2008, ReliabilityFirst formally concluded the audit process, finding PJM fully compliant with all planning standards subject to review. The process afforded PJM its first opportunity to present and explain its compliance documentation material. This communication process provided valuable information and experience that will aid in future organizational enhancements.

Reliability audits occur every three years. PJM's compliance obligations are being increasingly integrated into planning processes and documentation. To continue to test preparedness, PJM conducted a self assessment in November 2008, lead by the consulting group Power Decisions. For this exercise, PJM approached several PJM stakeholders to form a team of independent "assessors." They evaluated PJM's presentation of evidence documenting PJM compliance with operating and planning standards that were the subject of the formal audit in 2007. The self assessment found no instances of non-compliance in PJM's process or evidence. This

group did, however, provide valuable feedback that will assist PJM in further improvements and preparation for future formal audits by ReliabilityFirst.

9.2.3 – Expanded Interregional Coordination

The underpinnings of PJM's interregional planning responsibilities are codified in several joint or coordinated operating arrangements with adjoining transmission providers. These neighboring systems are shown on Map 9.1. In addition, FERC's Order No. 890 encourages interregional planning efforts. The Order directs transmission planners to take into account a broader view of need when planning transmission expansion. The primary emphasis is to expand the considerations during planning to factors beyond reliability criteria. Among consideration are ways to reduce overall cost to serve native load and integrate new resources on an aggregate basis. Recent national-level policy discussions suggesting electric grid and renewable resource initiatives increase the need for PJM to focus on long-term interregional planning coordination.

Interregional coordination enables PJM to join with other Eastern Interconnection transmission planners to integrate regional RTO plans and examine seams issues. Additionally, participation in these studies offers PJM the opportunity to anticipate and begin to investigate potential high-level impacts of developing interregional trends on PJM. These high-level, long-range analyses benefit from a broad multi-regional analysis. PJM participates in such forward-looking exercises, on behalf of and collaboratively with stakeholders and assesses results to inform and guide, as appropriate, the annual formulation of the RTEP.

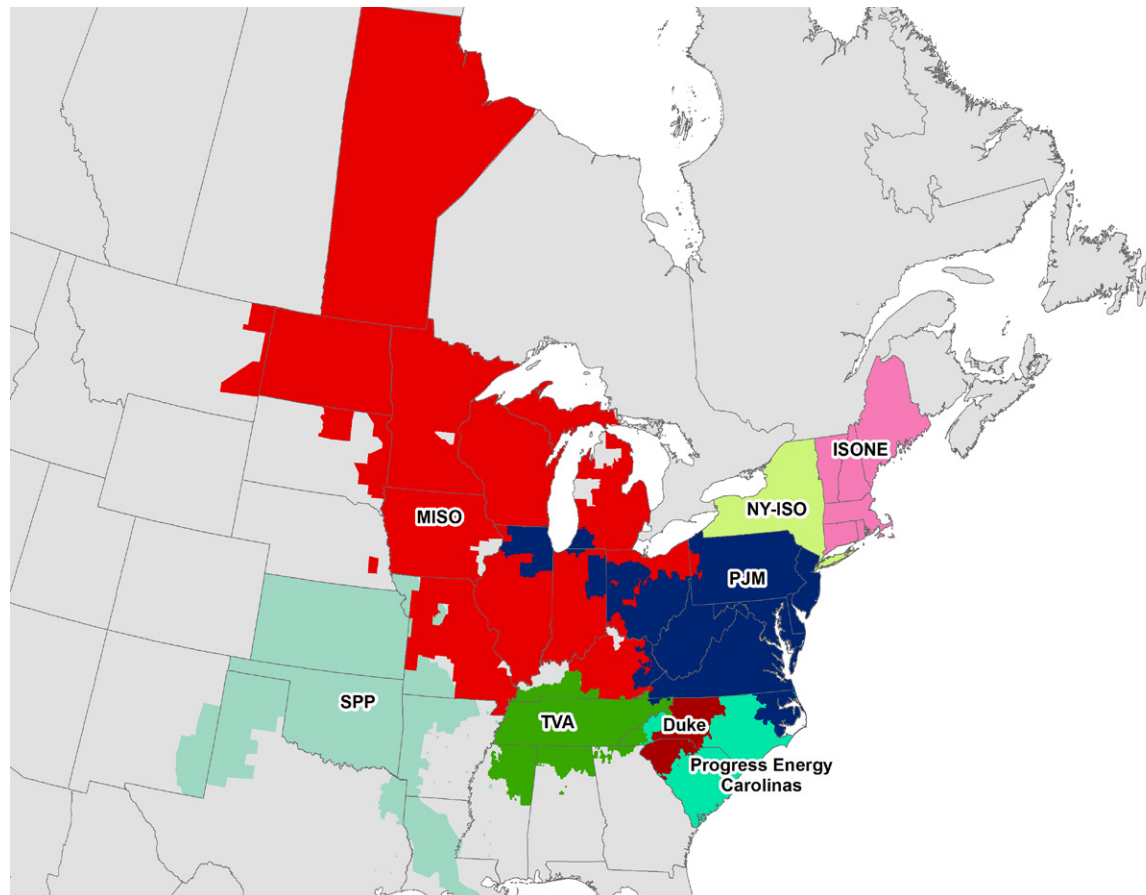
The techniques and methods used for interregional studies are of necessity a compromise among regions and consequently may not follow accepted PJM RTEP planning methods. Nevertheless these efforts produce valuable insights to the RTEP. PJM accepts these limitations in long-range interregional studies recognizing that actionable plans will require further analysis and review through PJM's approved RTEP process. From time to time progress on active interregional efforts will be reported through the PJM Planning Committee.

Joint Coordinated System Plan (JCSP)

In 2008 PJM continued to fulfill its obligations pursuant to Order 890 and several joint or coordinated operating arrangements with other regional transmission providers. In recognition of these various commitments and developing interest nationally in renewable resources, PJM, MISO, TVA and SPP cooperated in 2008 to conduct a joint economic and reliability analysis of a major portion of the Eastern Interconnection. The study emphasized two hypothetical future wind resource development scenarios. These scenarios were coupled with an assumption that such development is accompanied by conditions that would foster a push to develop substantial interregional electric grid infrastructure enhancements.

The broad participation in this study marked a significant increase in multilateral coordination among interregional entities. Thus, the scope of the effort in itself was an accomplishment that is expected to pave the way for future evolutions of interregional assessments. The 2008 interregional assessment first examined the reliability of the integration of the participant's currently anticipated 2018 regional system plans. Participants concluded

Map 9.1: PJM Interregional Planning



these individual plans are well coordinated as no significant unaddressed reliability issues were revealed.

The economic portion of the joint effort focused on the 2024 system with one scenario representing a reference case generation expansion and one scenario of heavy wind turbine expansion. Both cases maintained approximately a 15% generation planning reserve margin in excess of peak load. Based on the added assumption that transmission

is built to bridge interregional constraints, two transmission overlays were developed to illustrate an example of the possible magnitudes of the impacts that could result from such wind energy development scenarios. A final report for the reliability and economic phases of this work is expected to be completed in early 2009. More information regarding this study can be found at www.jcspstudy.org.

Department of Energy Interregional Wind Study (EWITS)

In August 2008 the Department of Energy (DOE) initiated the Eastern Wind Integration and Transmission Study (EWITS). PJM was invited to provide planning and operating technical review input to the EWITS effort as part of a Technical Review Committee. The EWITS is a long-range multi-regional examination of power system impacts of possible future wind industry development. The study region includes the Midwest ISO, PJM, Southwest Power Pool, Tennessee Valley Authority, New York ISO and ISO New England. The study is examining wind energy market penetration of 20% and 30% of total electric energy sales. The EWITS will tackle three main tasks: mesoscale wind resource modeling and development of wind power plant outputs for locations in the footprint, transmission analysis, and integration analysis including integration costs and operational impacts on the power system.

The DOE transmission analysis is leveraging the work of the interregional study effort initiated under the auspices of the JCSP. The EWITS scenarios will build on the same transmission methods used in the JCSP but will use updated wind data and wind siting analysis and will include an operating impact analysis. The EWITS work is expected to finish in fall 2009.

Agreement with the NC Collaborative

Duke Energy Carolinas, Progress Energy Carolinas, North Carolina Electric Membership Corporation and ElectricCities of North Carolina engage in the North Carolina Transmission Planning Collaborative (NC Collaborative.) In 2008 PJM agreed on the principles to enhance the level of planning cooperation among PJM and the participants of the NC Collaborative. Beginning in 2009 this agreement is expected to enhance identification of constraints and planned and proposed upgrades on this important PJM interface to the south.

Expanded Scope with NYISO

PJM and the NYISO agreed in 2007 to establish or confirm arrangements and protocols in furtherance of system reliability. With regard to planning activities, PJM and NYISO agreed to coordinate in accordance with the Northeast ISO/ RTO Coordination of Planning Protocol Agreement. During 2008 the two organizations agreed upon the principles for expanded planning cooperation especially related to the important interface between northern New Jersey and Southeast New York. In this regard, PJM and NY committed to a joint reliability and economic analysis of the area affecting this critical interface between the systems. This work is scheduled to be performed in 2009.