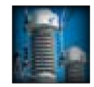
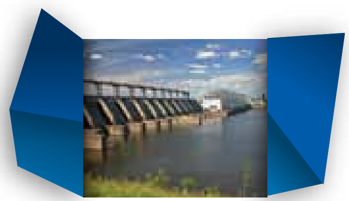
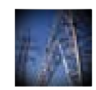
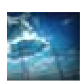
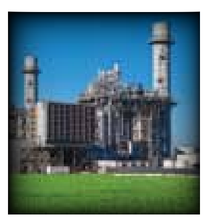
2013 RTEP – Input Data, Assumptions and Scope











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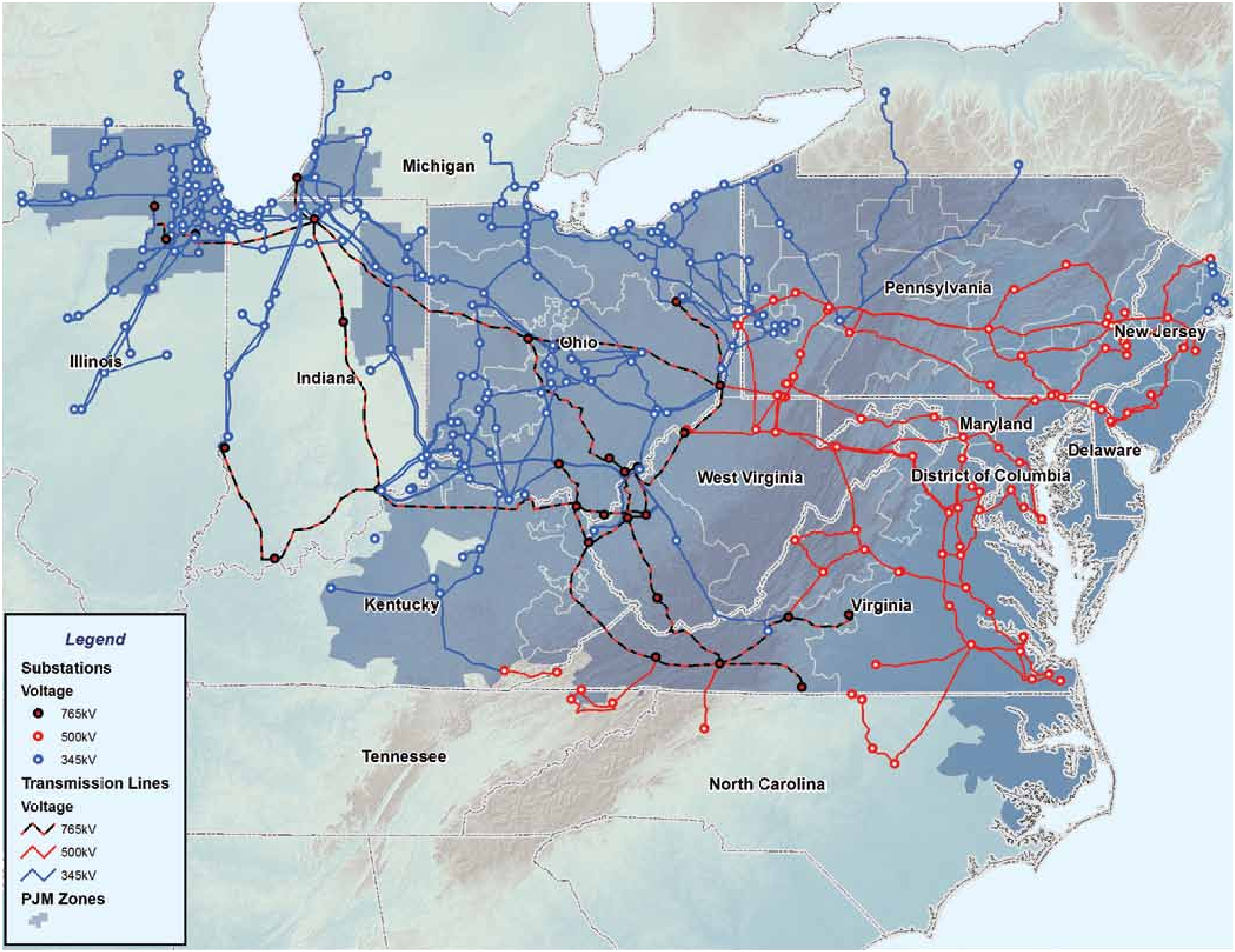


Michigan
Pennsylvania
New Jersey
Ohio
Illinois
Indiana
Maryland
Delaware
West Virginia
District of Columbia
Kentucky
Virginia
Tennessee
North Carolina
Legend
Substations
Voltage
765kV
500kV
345kV
Transmission Lines
Voltage
765kV
500kV
345kV
PJM Zones

Preface

This white paper is the first in a series that PJM intends to publish throughout the 2013 RTEP process as a vehicle to communicate RTEP assumptions, inputs and individual study results with greater detail and transparency.

RTEP Process Description

Summary level RTEP process description is provided in this white paper. The online resources noted below provide a more detailed understanding of RTEP process business rules and methodologies:

- The M-14 series of PJM Manuals contain the specific business rules that govern the entire RTEP process. Specifically, Manual 14B describes the methodologies associated with conducting planning studies and developing upgrades derived from them. PJM Manual 14B, "Regional Planning Process" can be found on PJM's website via the following URL: http://www.pjm.com/~/media/documents/manuals/m14b.ashx.
- Schedule 6 of the PJM Operating Agreement codifies the overall provisions under which PJM effects its Regional Transmission Expansion Planning Protocol, more familiarly known (and used throughout this document) as the "PJM RTEP Process." The PJM Operating Agreement can be found on PJM's website via the following URL: http://www.pjm.com/documents/agreements/~/media/documents/agreements/oa.ashx.
- The PJM Open Access Transmission Tariff (OATT) codifies provisions for generating resource interconnection, merchant/customer funded transmission interconnection, long-term firm transmission service and other upgrade specific requests. The PJM OATT can be found via the following URL: http://www.pjm.com/documents/agreements/~/media/documents/agreements/tariff.ashx.
- The status of individual baseline and network RTEP upgrades approved by the PJM Board can be found on PJM's website via the following URL: http://www.pjm.com/planning/rtep-upgrades-status.aspx.

Communicating RTEP Results – Stakeholder Forums

Transmission Expansion Advisory Committee (TEAC) and Sub-Regional RTEP Committee activities will continue throughout 2013, providing forums for PJM and stakeholders to exchange ideas, discuss study input assumptions and review results. PJM stakeholders are encouraged to participate in their ongoing activities. PJM TEAC items can be accessed from PJM's website via the following URL: http://www.pjm.com/committees-and-groups/committees/teac.aspx.

Each Sub-Regional RTEP Committee provides a forum for stakeholders to discuss more local planning concerns. Interested stakeholders can access Sub-regional RTEP Committee planning process information from PJM's website via the following URLs:

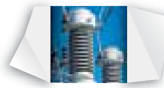
- PJM Mid-Atlantic Sub-Regional RTEP Committee: http://www.pjm.com/committeesand-groups/committees/srrtep-ma.aspx
- PJM Western Sub-Regional RTEP Committee: http://www.pjm.com/committees-and-groups/committees/ssrtep-w.aspx
- PJM Southern Sub-Regional RTEP Committee: http://www.pjm.com/committees-and-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

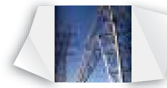
Independent State Agencies Committee (ISAC)

Commissioned in December 2011, the ISAC is a voluntary, stand-alone committee comprising representatives from regulatory and other agencies in state jurisdictions within the PJM footprint. Primarily, the ISAC provides a forum for states to provide input on RTEP assumptions and scenarios. Additional information is available via the following URL: http://pjm.com/committees-and-groups/isac.aspx.

FERC Order No. 1000

PJM efforts are under way to implement RTEP process changes to address FERC Order No. 1000 compliance. Additional RTEP white papers throughout 2013 will describe these changes and their impact on expansion plan development. At present, as process changes continue to unfold, readers are invited to follow the activities of PJM Regional Planning Process Task Force, per the following URL: http://www.pjm.com/committees-and-groups/task-forces/rpptf.aspx.





Section 1 – RTEP Process Overview

1.1:Introduction

This first 2013 RTEP white paper describes the input data, assumptions and scope associated with the body of analytical work comprising the second year of PJM's 24-month RTEP process and the 2013 12-month process as well. Implemented on January 1, 2012, the 24-month approach – outlined further in **Section 2** – permits PJM to incorporate two conventional twelve month bodies of work as well as a 24-month process to consider the need for and efficacy of longer lead-time backbone transmission facilities.

PJM's 2013 series of power flow cases will include the latest information and assumptions regarding zonal load forecasts, generating resources and transmission topology. **Section 3** discusses PJM's January 2013 load forecast as the basis for modeling power flow case bus loads. **Section 4** goes on to summarize the electrical topology, generation scenario and interchange modeled in those power flow cases.

Sections 5, **6** and **7** delineate the analytical scope of the conventional baseline, interregional and market efficiency studies, respectively, to be conducted in 2013. Each comprises an important dimension of determining regional transmission needs.

Section 8 describes the scope of scenario studies to be completed in 2013. These will include the continuation of at-risk generation and renewable portfolio standard (RPS) analyses as well as a demand resource buy-back sensitivity analysis.

1.2: RTO Planning Perspective

Today, as part of its ongoing regional transmission organization (RTO) responsibilities, PJM's RTEP Process considers the aggregate effects of many system trends: long-term growth in electricity use, generating plant construction, upgrades and retirement; broader generation development patterns – including the evolution of renewable resources – as well as the impacts of demand resource and energy efficiency programs.

This process culminates in one recommended plan – one RTEP – for the entire PJM footprint that is submitted to PJM's independent Board of Managers (PJM Board) for consideration and approval. Under the terms of the PJM Operating Agreement the PJM Board's approval then obligates transmission owning utilities in PJM to build the facilities specified in the RTEP. This includes construction of new transmission lines as well as upgrades to existing transmission assets.

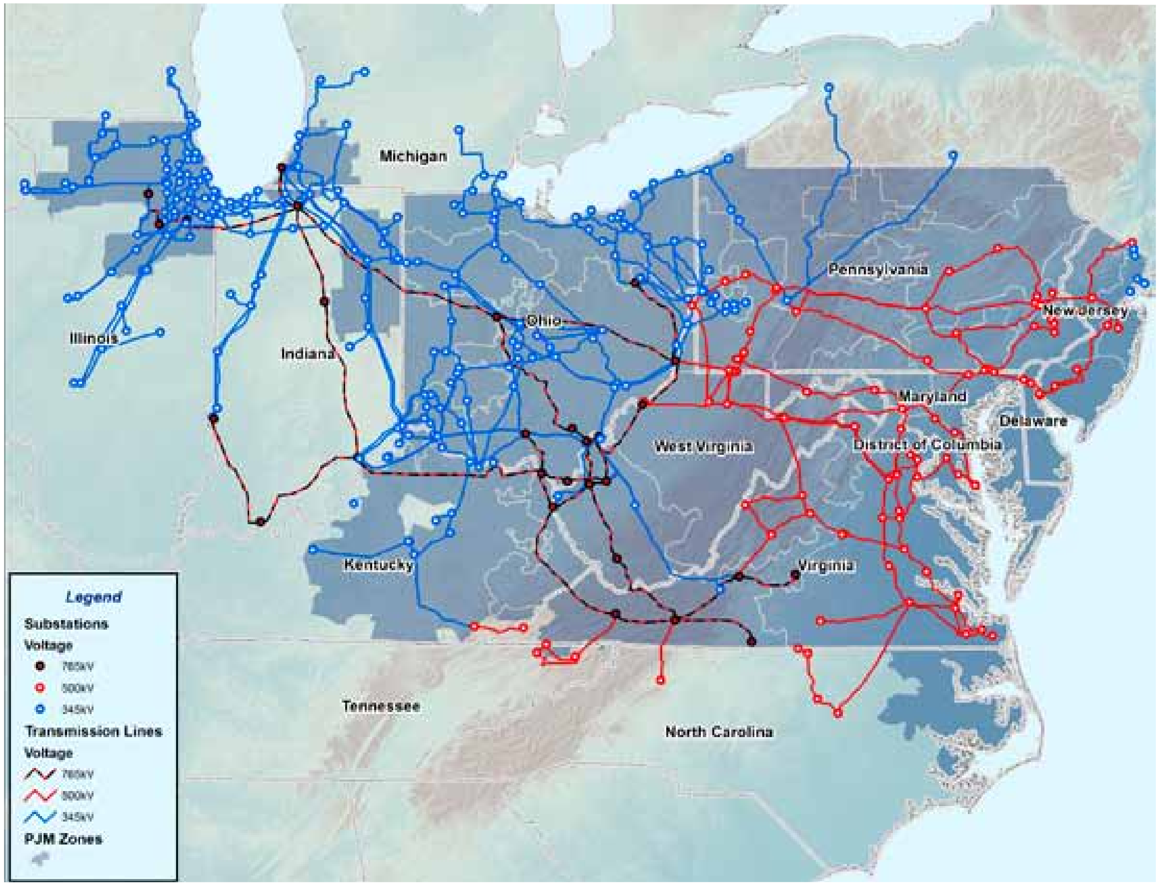
PJM Footprint

PJM is a FERC-approved RTO that coordinates the movement of wholesale electricity across a high voltage transmission system in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia as shown on **Map 1.1**

PJM's RTEP identifies transmission system additions and improvements needed to keep electricity flowing to more than 61 million people throughout these 13 states and the District of Columbia. PJM's footprint encompasses major U.S. load centers from the Atlantic coast to Illinois's western border including the metropolitan areas in and around Baltimore, Chicago, Columbus, Cleveland, Dayton, Newark and northern New Jersey, Norfolk, Philadelphia, Pittsburgh, Richmond, Toledo and the District of Columbia.

Collaborating with more than 800 members, PJM dispatches more than 183,600 MW of generation capacity over 62,000 miles of transmission lines (including the recently integrated EKPC transmission zone). The PJM system includes many key U.S. Eastern Interconnection transmission arteries, as **Map 1.1** shows. PJM's unique interstate geography and electrical topology provide members access to PJM's regional power markets as well as those of adjoining systems.

Map 1.1: PJM Backbone Transmission System



1.3: One Regional Plan

Most importantly, regional planning addresses reliability – the need to keep the lights on. The market efficiency dimension of regional planning seeks to identify transmission enhancements that lower costs to consumers by relieving congestion. Projects that improve reliability can also improve system economics, and vice versa.

PJM's RTEP process encompasses a comprehensive assessment of the transmission system's ability to meet all applicable reliability planning criteria. RTEP analyses assess system compliance with the thermal, reactive, stability and short circuit NERC standards for Category A (TPL-001), Category B (TPL-002) and Category C (TPL-003) events, over both five-year and 15-year planning horizons. When PJM identifies NERC Reliability Standard violations, PJM must develop transmission upgrade plans to solve them. NERC reliability standards in the context of the RTEP process are discussed in PJM Manual 14B, accessible from PJM's website via the following URL: http://pjm.com/~/media/documents/manuals/m14b.ashx.

This process culminates in one recommended plan – one RTEP – for the entire PJM footprint submitted to PJM's independent Board of Managers (PJM Board) periodically throughout the year to resolve identified reliability criteria violations. Once approved by the PJM Board, they become part of PJM's overall RTEP. Board approval then binds the designated responsible party to construct the approved transmission system upgrades.

Integrated Nature of a Regional Plan

PJM addresses transmission expansion planning from a regional perspective, spanning Transmission Owner zonal boundaries and state boundaries to address the comprehensive system-wide impact of myriad upgrade drivers. The relationship between reliability criteria violation and upgrade location generally takes one of two forms:

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

2. ***Regional*** - Reliability criteria violations in one or more TO zones may be driven by some combination of system factors including those potentially arising some distance away. For example, voltage criteria violations in eastern portions of the PJM system may not be caused by a local problem but rather by heavier west-to-east transfers from Mid-Western U.S. generating sources to eastern PJM load centers.

Consequently, PJM is able to develop optimal regional solutions to solve reliability criteria violations. Otherwise, addressing them individually and mutually exclusive of one another could yield economically inefficient transmission solutions.

*** NOTE**

NERC TPL Standards: PJM is aware of the upcoming changes to the NERC TPL standards and is actively preparing for the implementation of these requirements.

1.4: RTEP Decision-Making Process

Driven by a confluence of growing industry trends (particularly generation), regulatory mandates and FERC Order No. 1000 compliance, PJM continues to enhance its decision-making process so that the right RTEP upgrades are triggered at the right time. **Figure 1.1** shows PJM's expanded RTEP process study, communications and stakeholder elements. While reliability and market efficiency requirements will continue to be a fundamental part of the RTEP protocol, decision making has been expanded to examine public policy scenarios and variability in the factors that have traditionally driven transmission expansion.

Public Policy Drivers

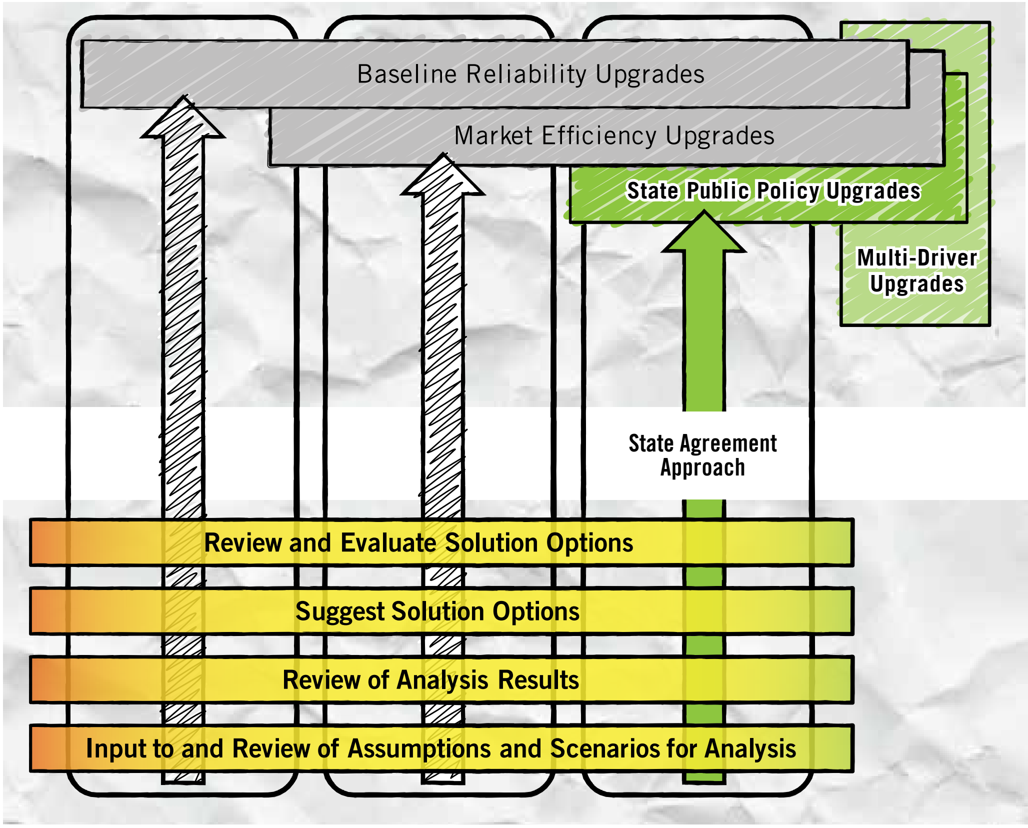
The critical role that the transmission system plays in effecting federal and state energy and environmental public policy continues to increase. Indeed, while the existence of violations of NERC Reliability Standards has been the basis for PJM's determination of need, construction of major transmission infrastructure will likely impact transmission planning decisions and may require action in some instances to ensure reliability.

At-Risk Generation

At-risk generators – discussed in **Section 8.2** – face the real possibility of deactivation given the economic impacts of increasing operating costs associated with unit age – some more than 40 years old – and environmental public policy compliance. Plant costs drive the ability of a generator to realize consistent revenue streams from PJM's energy, capacity and ancillary service markets. A key factor placing a plant at-risk is its inability to clear a capacity auction, given its costs compared to other competing resources:

- other more efficient plants
- renewable energy resources
- demand resource and energy efficiency programs

Figure 1.1: RTEP Decision-making Process



Generator deactivations are both driven by and directly impact RPM auction activity. PJM staff and stakeholders have made significant strides over the past several years assessing how at-risk generation will impact system reliability, capacity adequacy and economic system operation. At-risk generation scenario analysis will remain an important dimension of PJM's RTEP Process given the implementation of EPA rule makings with effective dates through 2015, coupled with unfolding state environmental rules like those in New Jersey. PJM will continue to refine and update RTEP studies to provide PJM and stakeholders with additional understanding of system impacts.

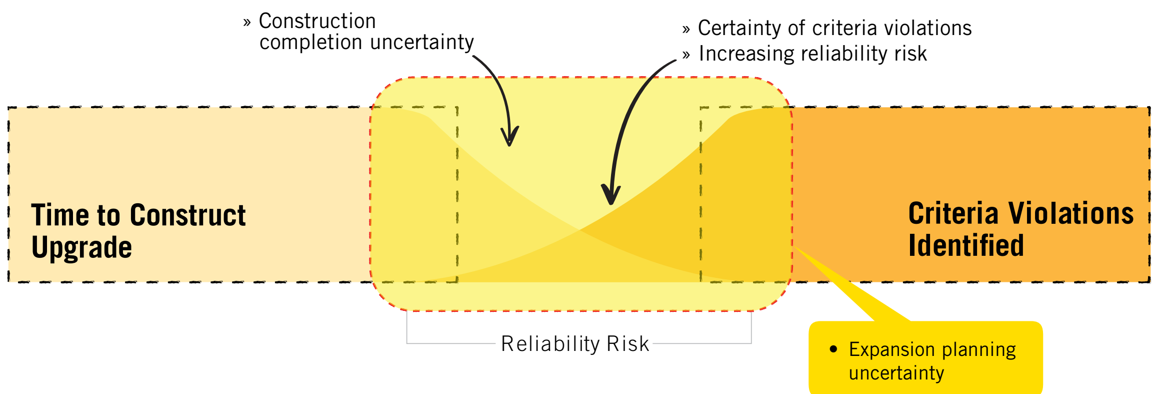
State RPS Initiatives

Importantly, as discussed in **Section 8.3**, ten states and the District of Columbia within PJM have adopted RPS mandates, which require electricity suppliers to purchase specified amounts of renewable energy as part of their state supply portfolio. Current RPS goals range from 10 percent to 25 percent over the next decade.

Backbone Transmission Expansion Uncertainty and Risk

Uncertainty around the onset of reliability criteria violations is not characterized by a definitive step function. As shown in **Figure 1.2**, input parameter volatility can shift violations earlier or later than initially identified. As part of the 2013 RTEP process, PJM will review – as it does every year – transmission plans developed in earlier years. By doing so PJM can determine whether as a result of changing assumptions previously approved transmission upgrades are still required. And, if so, whether they are still required in the year originally identified. Planning is a dynamic process. System conditions change over time, driving the need to adjust assumptions used in planning studies and reevaluate decisions made in previous planning cycles.

Figure 1.2: Transmission Expansion Uncertainty and Risk

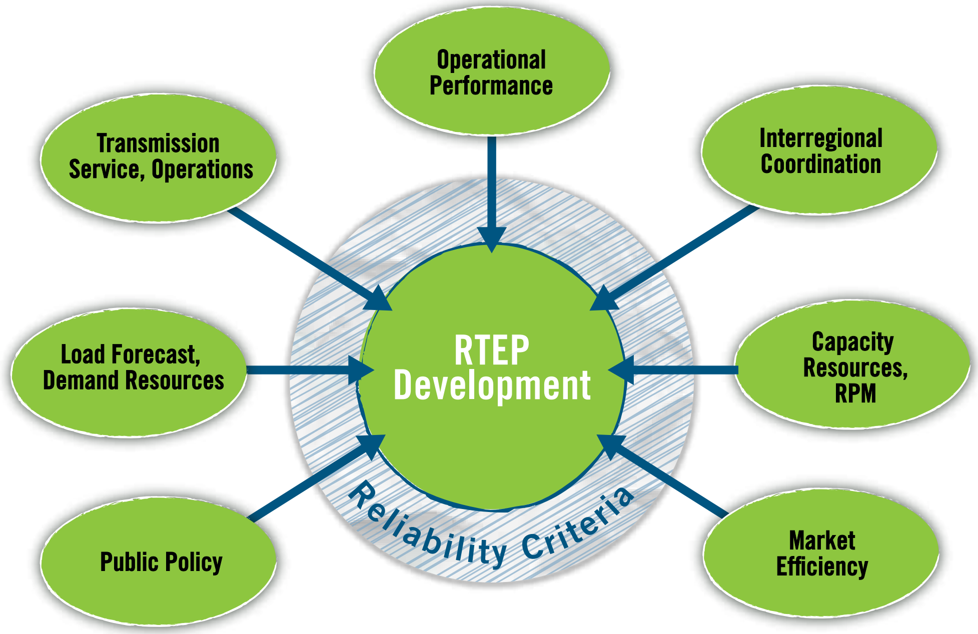


1.5: RTEP Development Drivers

A 15-year long-term horizon allows PJM to consider the aggregate effects of many system drivers, shown in **Figure 1.3**. Initially, beginning with its inception in 1997, PJM's RTEP consisted mainly of upgrades driven by load growth and generating resource interconnection requests. Today, PJM's RTEP process considers the aggregate effects of many additional system trends, many driven by public policy decisions at federal and state levels: generating plant retirements driven by environmental regulations; new generating plants powered by natural gas, wind and solar; and impacts introduced by demand resources and energy efficiency programs.

While the existence of NERC Reliability Standard violations drives transmission expansion, construction of additional infrastructure will likely be necessary to support achievement of public policy goals. In 2013, PJM will continue to expand its traditional bright-line baseline tests with scenario studies to consider public policy and other transmission expansion drivers, described further in **Section 8** of this white paper.

Figure 1.3: RTEP Development Drivers



Section 2 – 24-Month Planning Cycle

2.1: 24-Month Planning Cycle

In compliance with the requirements of the NERC TPL (Transmission Planning) Reliability Standard, PJM's 24-month planning process includes the following components, shown in **Figure 2.1**:

1. Two 12-month cycles, each of which examines the near-term need (years one through five) for transmission upgrades.

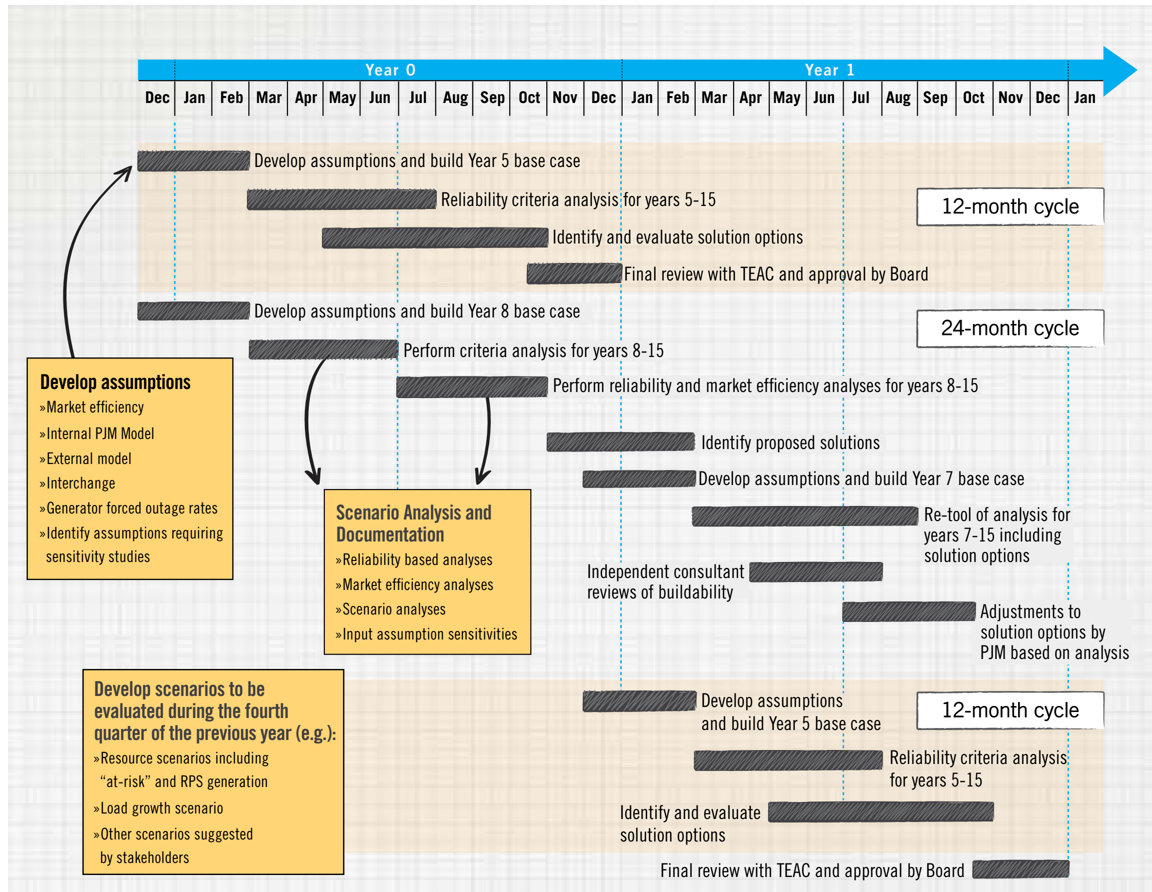
2. One 24-month cycle, which examines the long-term need (15 years forward) for transmission upgrades.

This 24-month planning process identifies upgrades from baseline, generation interconnection, market efficiency and operational performance analyses. These are reviewed with stakeholders through the activities of the Transmission Expansion Advisory Committee (TEAC) and approved by the PJM Board.

*** NOTE**

Activities and timelines shown on **Figure 2.1** are for illustrative purposes. The actual timeline may vary to some degree to be responsive to RTEP and stakeholder needs.

Figure 2.1: RTEP Process 24-Month Cycle



Near-Term Planning (5-year out)

Consistent with established practice, the first step in PJM's 2013 RTEP process has been to develop the set of analytical assumptions. These assumptions have been vetted with stakeholders at Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP Committee meetings.

As **Section 2.2** will describe, the yearly series of cases includes the latest load, resource and transmission topology information to develop a 5-year-out, 2018 base case for near-term baseline reliability analysis. PJM Manual 14B, Attachment H provides more specific detail regarding the power system modeling data used to create RTEP base cases: http://pjm.com/~/media/documents/manuals/m14b.ashx.

Near-term baseline analysis completed as part of each 12-month planning cycle includes testing on all bulk electric system (BES) facilities against applicable reliability planning criteria as described in PJM Manual 14B and summarized in this white paper for the planning cycle beginning January 1, 2013. Ultimately, solutions to address the criteria violations are developed, reviewed with the TEAC and Sub-Regional RTEP Committees and submitted to the PJM Board for approval. The baseline system that emerges from this process - without reliability criteria violations - then also becomes the basis for subsequent interconnection queue studies.

Long-Term Planning (15-year out)

Long-term planning analyses permit PJM to examine reliability criteria violations the solutions for which may be of a more significant scope including, for example, high voltage transmission lines. Such facilities typically require longer lead times to be completed and generally provide more regional benefits.

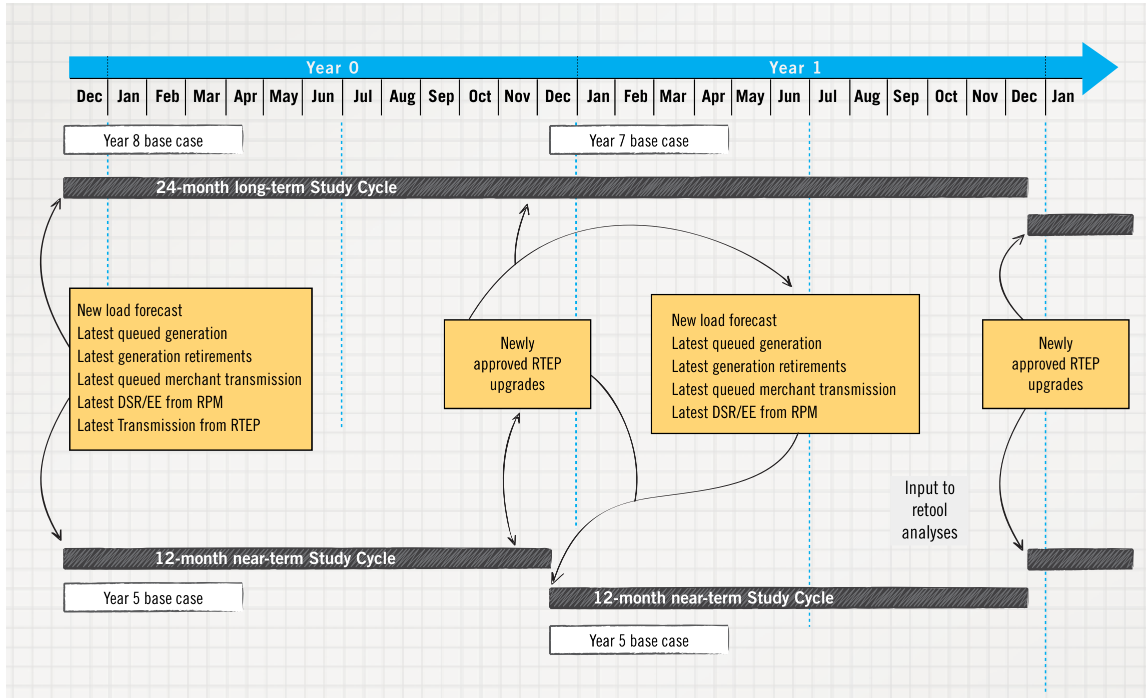
At the start of the 24-month cycle a base case is developed for Year 8 in order to examine system conditions in years eight through fifteen. Then, at the start of the second 12 month period in each 24 month cycle, a "Year 7" case is developed to continue this 15-year long-term analysis begun in the first twelve months of the 24-month cycle, as shown in **Figure 2.1**. Thus, in 2013, PJM will continue its 15-year, 2020 case analysis begun in 2012.

2.2: Power Flow Case Development

Underlying the RTEP enhancement drivers are a set of power flow modeling assumptions and an extensive array of input data. PJM must first incorporate expected future system conditions in its power flow simulation models. PJM's 2013 series of cases will include the latest information and assumptions regarding zonal load forecasts, generating resources, transmission topology, demand resources and power transfer levels with adjoining systems (known also as interchange), shown in **Figure 2.2** and discussed in **Sections 3** and **4.**

Credible, consistent power system study results depend on accurate power system modeling data. PJM employs a number of models and analytical techniques to create and maintain the simulation models used for the RTEP studies. To that end, base case creation necessarily remains a collaborative process between PJM and members. Attachment H of PJM Manual 14B, Power System Modeling Data, describes the technical aspects of the data used to create RTEP base cases. Manual 14B is accessible from PJM's website via the following URL: http://pjm.com/~/media/documents/manuals/m14b.ashx.

Figure 2.2: RTEP Process Base Case Development



Transmission Owner Collaboration

PJM's 2013 RTEP Process near-term analysis focuses on a five-year forward, 2018 case year. Doing so provides sufficient lead-time to permit identified transmission upgrades to be constructed and placed in service.

PJM's case creation process began with sending a preliminary, draft power flow case, contingency files, and behind the meter calculations to each Transmission Owner to be updated and submitted back to PJM. Each Transmission Owner has also reviewed and updated respective contingency files to reflect case topology changes. Contingency analysis included all BES facilities, all tie lines to adjoining systems and all lower voltage facilities operated by PJM.

Simulation Tools and Supporting Files

PJM uses commercially available software including but not limited to: Power System Simulation for engineering (PSS/E) for modeling and simple analysis; Managing and Utilizing System Transmission (MUST) and Transmission Adequacy & Reliability Assessment (TARA) for more complex power flow analysis. Supporting contingency files, monitor files, subsystem files and unit availability data are also updated each year.

- ***Contingency files*** contain the sets of transmission facility outage combinations to be studied.
- ***Monitor files*** identify the specific facilities to be examined for potential reliability criteria violations: Such facilities include PJM BES elements, tie lines to neighboring systems, specified facilities in MISO and all lower voltage facilities operated by PJM. Thermal and voltage limits for each monitored facility are consistent with those used in operations.

- ***Subsystem files,*** used in deliverability analysis, identify source-sink pairs used in modeling power transfers.

PJM also maintains files that contain generator availability probabilities used in deliverability studies to establish peak-load test condition dispatch scenarios. These files play a crucial role in the actual analysis of study year power flow models, ensuring that reliability criteria violations are accurately identified.

Section 3 – Load Forecast Modeling

3.1: Forecasting Process

Fundamentally, PJM's planning process identifies future system transmission needs based on power flow studies that reveal NERC reliability criteria violations. Power flow study models incorporate the effect of many system expansion drivers. Up-to-date, comprehensively determined zonal load forecasts – the basis for modeling power flow case bus loads – are essential if transmission expansion studies are to yield plans that will continue to ensure reliable and economically efficient system operations.

Methods and Econometrics

PJM's load forecasting methodology incorporates the three classes of variables shown in **Figure 3.1**:

1. Calendar effects such as day of the week, month and holidays
2. Economic conditions
3. Weather conditions across the RTO

The economic dimension of load forecasting employs an indexed variable that incorporates six economic measures (Gross Domestic Product, Gross Metropolitan Product, real personal income, population, households, and non-manufacturing employment) into one measure, which allows for localized treatment of economic effects within a zone.

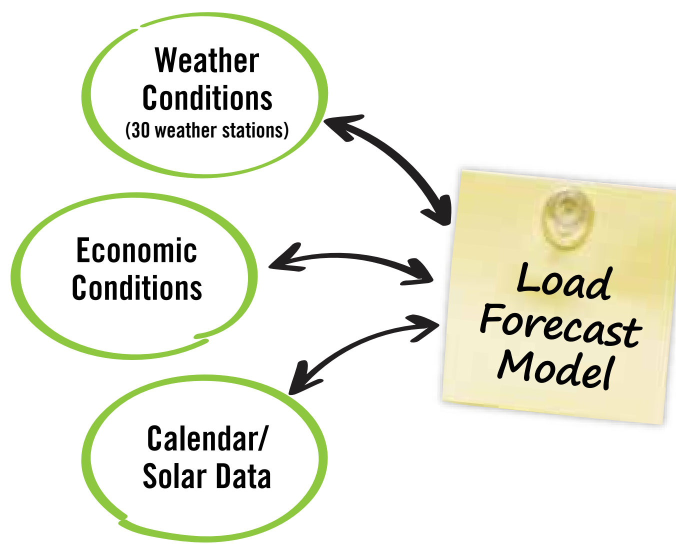
PJM has contracted with an outside economic services vendor to provide economic forecasts for all areas within the PJM footprint on an ongoing basis. To account for weather conditions across the RTO, PJM calculates a weighted average of temperature, humidity and wind speed as the weather drivers. PJM obtains weather data from over 30 weather stations across PJM.

3.2: January 2013 Forecast

PJM's January 2013 load forecast covered the 2013 through 2028 planning horizon, highlights of which are summarized here. The complete January 2013 PJM Load Forecast report is accessible from PJM's website via the following link: http://www.pjm.com/~/media/documents/reports/2013-pjm-load-report.ashx.

As that report states, PJM's 2018 RTO summer peak is forecasted to be 168,813 MW, including the load of American Transmission Systems Inc. (ATSI), Duke Energy Ohio and Kentucky (DEO&K), and East Kentucky Power Cooperative (EKPC). ATSI integrated on June 1, 2011; DEO&K integrated on January 1, 2012; EKPC integrated into PJM on June 1, 2013.

Figure 3.1: Load Forecast Model



General Forecasting Trends

Table 3.1 summarizes the seasonal TO zonal summer and winter 10-year forecasts and load growth rates for 2013 through 2023.

Table 3.2 compares 10-year load growth rates for each PJM TO zone and for the overall RTO, per the respective load forecasts produced each year, 2009 through 2013. PJM's RTEP process ensures that the most recent changes to assumptions and system conditions are reflected in its models. To that end, load forecast trends from 2009 through 2013 reflect the impact of the broader U.S. economic recession and tentative recovery since Fall 2009, driving lower short-term load forecasts.

Table 3.1: 2013 Load Forecast Report – Transmission Owner Zonal Summer/Winter Peaks

	Summer Peak (MW)			Winter Peak (MW)		
T. O.	2013	2023	Growth Rate (%)	2012/13	2022/23	Growth Rate (%)
Atlantic City Electric Company	2,733	3,053	1.1%	1,773	1,943	0.9%
Baltimore Gas and Electric Company	7,218	8,034	1.1%	5,968	6,363	0.6%
Delmarva Power and Light	4,141	4,717	1.3%	3,362	3,727	1.0%
Jersey Central Power and Light	6,253	7,068	1.2%	3,929	4,421	1.2%
Metropolitan Edison Company	2,978	3,509	1.7%	2,616	3,046	1.5%
PECO Energy Company	8,722	10,026	1.4%	6,658	7,663	1.4%
Pennsylvania Electric Company	2,918	3,535	1.9%	2,888	3,515	2.0%
PPL Electric Utilities Corporation	7,271	8,264	1.3%	7,313	8,158	1.1%
Potomac Electric Power Company	6,855	7,392	0.8%	5,465	5,983	0.9%
Public Service Electric and Gas Company	10,562	11,475	0.8%	6,906	7,500	0.8%
Rockland Electric Company	420	447	0.6%	233	245	0.5%
UGI	195	218	1.1%	198	217	0.9%
Diversity - Mid-Atlantic	-530	-512		-652	-705	
Mid-Atlantic	59,736	67,226	1.2%	46,657	52,076	1.1%
American Electric Power Company	23,793	26,605	1.1%	22,955	25,303	1.0%
Allegheny Power	8,661	9,829	1.3%	8,558	9,734	1.3%
American Transmission Systems, Inc.	13,270	14,535	0.9%	10,692	11,373	0.6%
Commonwealth Edison Company	22,761	26,742	1.6%	15,931	18,395	1.4%
Dayton Power and Light	3,442	4,069	1.7%	2,867	3,304	1.4%
Duke Energy Ohio and Kentucky	5,530	6,244	1.2%	4,397	4,764	0.8%
Duquesne Light Company	2,966	3,331	1.2%	2,198	2,390	0.8%
East Kentucky Power Cooperative	1,910	2,124	1.1%	2,329	2,482	0.6%
Diversity - Western **	-1,721	-2,047		-1,548	-1,828	
Western **	80,612	91,432	1.3%	68,379	75,917	1.1%
Dominion Virginia Power	19,619	23,558	1.8%	17,311	20,288	1.6%
Southern	19,619	23,558	1.8%	17,311	20,288	1.6%
Diversity - RTO **	-4,414	-4,777		-1,537	-1,663	
PJM RTO **	155,553	177,439	1.3%	130,810	146,618	1.1%

** Note: In the 2013 Report, Western and PJM RTO numbers include EKPC.

Table 3.2: Annual 2009 through 2013 Forecasts: Summer Peak Load Comparisons

	2009 Load Forecast Report			2010 Load Forecast Report			2011 Load Forecast Report			2012 Load Forecast Report			2013 Load Forecast Report		
	Summer Peak (MW)			Summer Peak (MW)			Summer Peak (MW)			Summer Peak (MW)			Summer Peak (MW)		
T. O.	2009	2019	Growth Rate (%)	2010	2020	Growth Rate (%)	2011	2021	Growth Rate (%)	2012	2022	Growth Rate (%)	2013	2023	Growth Rate (%)
Atlantic City Electric Company	2,692	3,533	2.8%	2,734	3,443	2.3%	2,664	3,085	1.5%	2,703	3,017	1.1%	2,733	3,053	1.1%
Baltimore Gas and Electric Company	7,303	8,745	1.8%	7,456	8,919	1.8%	7,388	8,420	1.3%	7,221	8,086	1.1%	7,218	8,034	1.1%
Delmarva Power and Light	3,972	4,882	2.1%	4,023	4,601	1.4%	4,148	4,608	1.1%	4,111	4,695	1.3%	4,141	4,717	1.3%
Jersey Central Power and Light	6,357	7,621	1.8%	6,440	7,611	1.7%	6,396	7,239	1.2%	6,244	7,063	1.2%	6,253	7,068	1.2%
Metropolitan Edison Company	2,866	3,334	1.5%	2,920	3,444	1.7%	2,956	3,387	1.4%	2,974	3,513	1.7%	2,978	3,509	1.7%
PECO Energy Company	8,455	9,538	1.2%	8,528	9,821	1.4%	8,696	9,684	1.1%	8,781	10,156	1.5%	8,722	10,026	1.4%
Pennsylvania Electric Company	2,786	3,305	1.7%	2,843	3,420	1.9%	2,889	3,496	1.9%	2,917	3,538	1.9%	2,918	3,535	1.9%
PPL Electric Utilities Corporation	7,106	7,985	1.2%	7,161	8,213	1.4%	7,263	7,993	1.0%	7,243	8,303	1.4%	7,271	8,264	1.3%
Potomac Electric Power Company	6,960	7,823	1.2%	7,048	7,909	1.2%	6,986	7,710	1.0%	6,876	7,494	0.9%	6,855	7,392	0.8%
Public Service Electric and Gas Company	10,858	12,470	1.4%	10,921	12,428	1.3%	10,810	11,836	0.9%	10,575	11,588	0.9%	10,562	11,475	0.8%
Rockland Electric Company	435	496	1.3%	435	493	1.3%	430	474	1.0%	419	464	1.0%	420	447	0.6%
UGI	190	207	0.9%	190	210	1.0%	195	208	0.6%	195	217	1.1%	195	218	1.1%
Diversity - Mid-Atlantic	-359	-427		-530	-385		-415	-334		-802	-486		-530	-512	
Mid-Atlantic	59,621	69,512	1.5%	60,169	70,127	1.5%	60,406	67,806	1.2%	59,457	67,648	1.3%	59,736	67,226	1.2%
American Electric Power Company	23,682	26,554	1.2%	23,287	26,631	1.4%	23,673	26,540	1.1%	23,716	26,709	1.2%	23,793	26,605	1.1%
Allegheny Power	8,538	9,889	1.5%	8,661	9,909	1.4%	8,655	9,594	1.0%	8,625	9,850	1.3%	8,661	9,829	1.3%
American Transmission Systems, Inc.				13,040	14,888	1.3%	13,364	14,991	1.2%	13,278	14,570	0.9%	13,270	14,535	0.9%
Commonwealth Edison Company	22,472	27,722	2.1%	22,536	27,965	2.2%	22,689	26,528	1.6%	22,852	26,997	1.7%	22,761	26,742	1.6%
Dayton Power and Light	3,399	3,945	1.5%	3,368	3,835	1.3%	3,433	3,963	1.4%	3,382	4,032	1.8%	3,442	4,069	1.7%
Duke Energy Ohio and Kentucky							5,669	6,198	0.9%	5,592	6,385	1.3%	5,530	6,244	1.2%
Duquesne Light Company	2,862	3,257	1.3%	2,883	3,318	1.4%	2,944	3,280	1.1%	2,935	3,289	1.1%	2,966	3,331	1.2%
East Kentucky Power Cooperative													1,910	2,124	1.1%
Diversity - Western **	-1,252	-1,646		-1,684	-2,192		-1,735	-2,081		-1,689	-2,016		-1,721	-2,047	
Western **	59,701	69,721	1.6%	72,091	84,354	1.6%	78,692	89,013	1.2%	78,691	89,816	1.3%	80,612	91,432	1.3%
Dominion Virginia Power	18,982	23,603	2.2%	19,779	25,387	2.5%	19,661	24,206	2.1%	19,550	23,537	1.9%	19,619	23,558	1.8%
Southern	18,982	23,603	2.2%	19,779	25,387	2.5%	19,661	24,206	2.1%	19,550	23,537	1.9%	19,619	23,558	1.8%
Diversity - RTO **	-3,876	-4,219		-4,248	-5,144		-4,376	-4,965		-3,916	-4,581		-4,414	-4,777	
PJM RTO **	134,428	158,617	1.7%	147,791	174,724	1.7%	154,383	176,060	1.3%	153,782	176,420	1.4%	155,553	177,439	1.3%

** Note: In the 2009 Report, Western and PJM RTO numbers do not include ATSI. In the 2010 Report, Western and PJM RTO numbers include ATSI. In the 2011 and 2012 Report, Western and RTO numbers include ATSI and DEO&K. In the 2013 Report, Western and RTO numbers include ATSI, DEO&K and EKPC.

2013 Forecast Summer Zonal Load Growth Rates

Average 10-year annualized summer growth rates for individual PJM zones vary from a low of 0.6 percent in the RECO zone to a high of 1.9 percent in the PENELEC zone as shown in **Figure 3.2** and **Figure 3.3**. The forecasted summer peak for 2013 is 155,553 MW and is projected to grow to 177,439 MW in 2023, a 10-year increase of 21,886 MW.

Figure 3.2: PJM Mid-Atlantic Summer Peak Zonal Load Growth Rate Comparison – 2013 through 2023

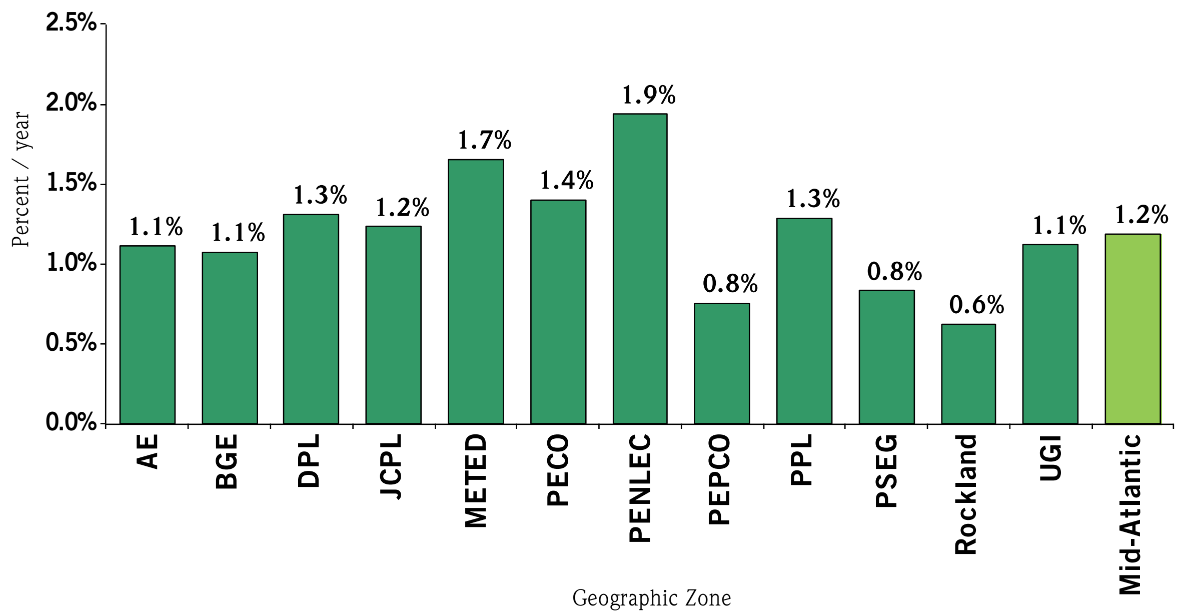
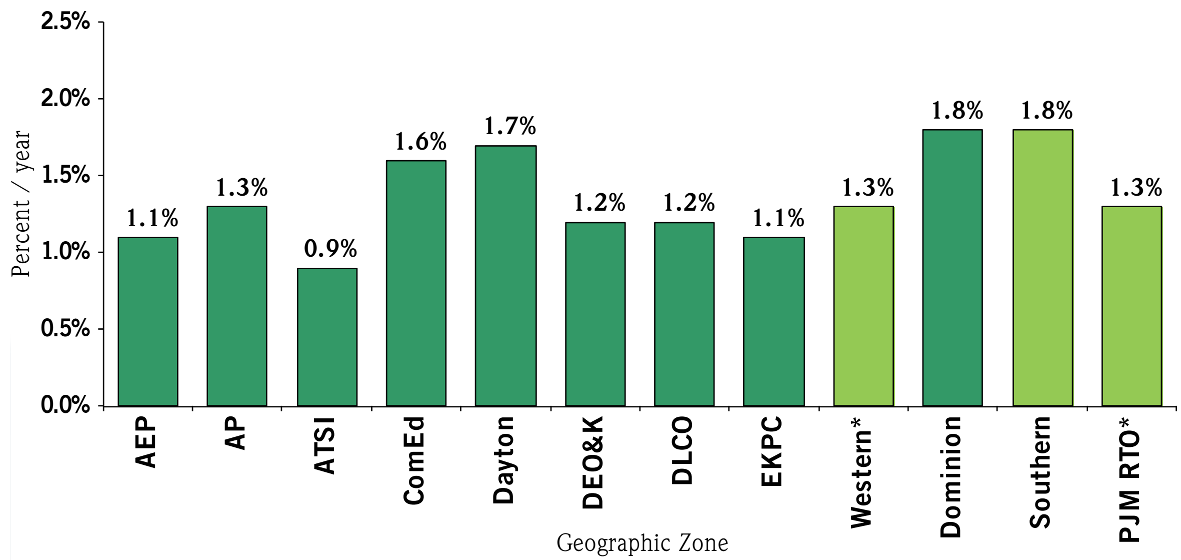


Figure 3.3: PJM Western and Southern Summer Peak Zonal Load Growth Rate Comparison – 2013 through 2023*



*** NOTE**

Figure 3.3*: Western and PJM RTO values include ATSI, DEO&K, and EKPC

2013 Forecast Winter Zonal Load Growth Rates

The PJM RTO weather normalized winter peak is forecasted to grow at an average rate of 1.1 percent per year for the next 10-year period. The PJM RTO winter peak is forecasted to be 146,618 MW in 2022/23, an increase of 15,808 MW over the 2012/13 peak of 130,810 MW. Individual geographic zone growth rates vary from 0.5 percent to 2.0 percent, as shown in **Figure 3.4** and **Figure 3.5**.

Figure 3.4: PJM Mid-Atlantic Winter Peak Zonal Load Growth Rates – 2013 through 2023

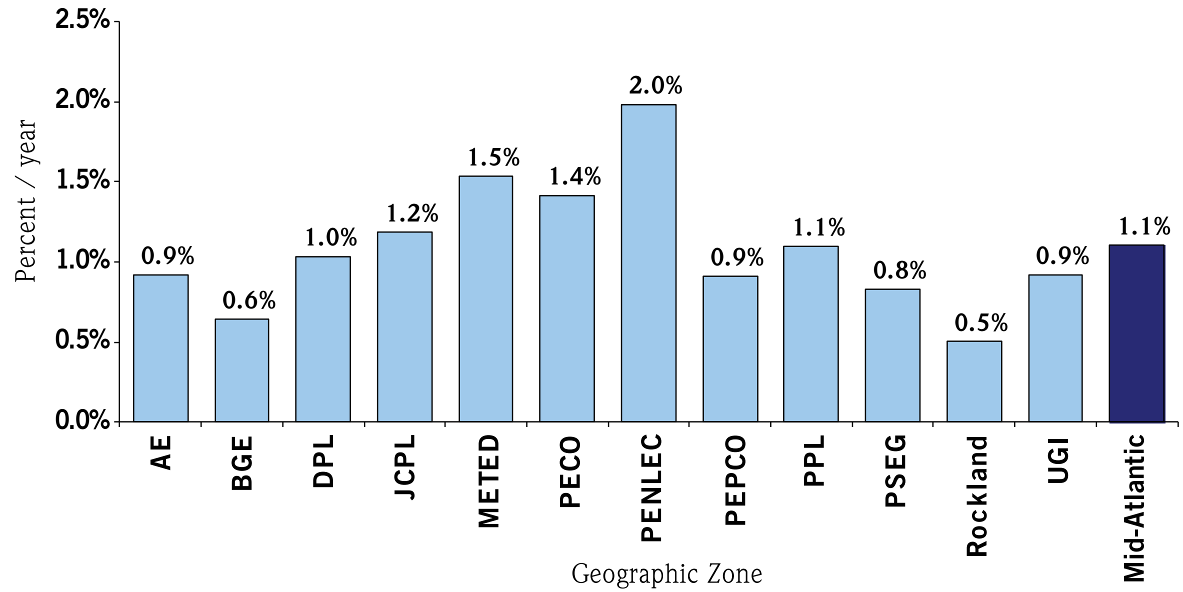
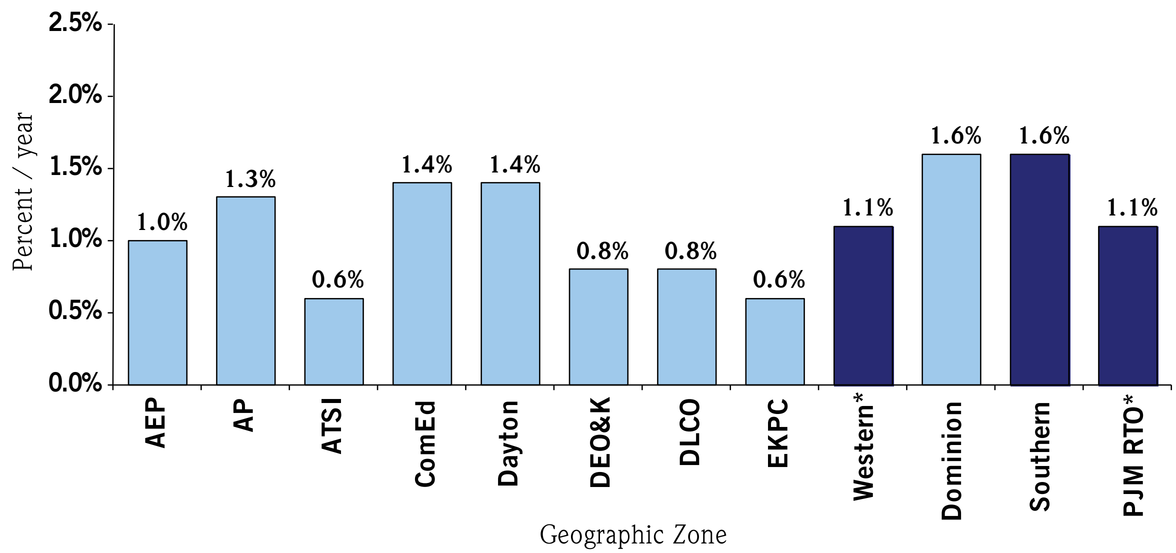


Figure 3.5: PJM Western and Southern Winter Peak Zonal Load Growth Rates – 2013 through 2023*



*** NOTE**

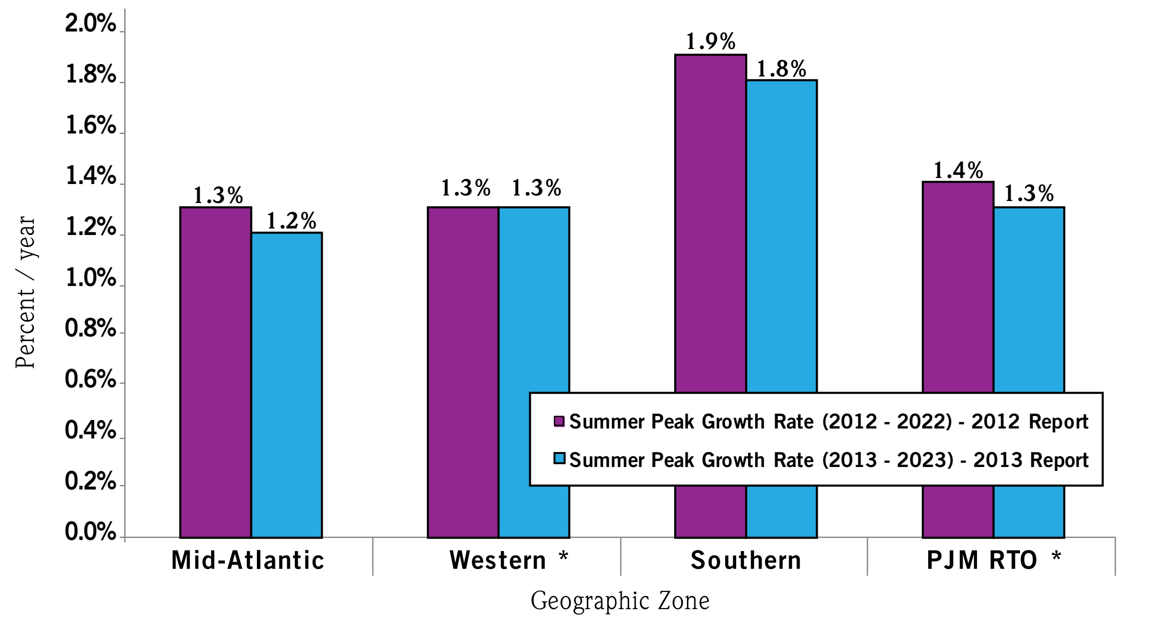
Figure 3.5*: Western and PJM RTO values include ATSI, DEO&K and EKPC.

Sub-Regional Forecast Trends

Figure 3.6 provides a comparison, from the 2012 and 2013 Load Forecast reports, of the 10-year summer peak load growth rates on a sub-regional basis. Load growth rates for Mid-Atlantic PJM, Southern PJM and the RTO as a whole decreased by a 0.1 percentage points each in the 2013 forecast over the 2012 forecast. Western PJM subregional forecasted load growth rate remained the same at 1.3 percent.

Figure 3.7 provides a summary comparison based on load growth rates trends from the respective January load forecast over each of the last five years, from 2009 through 2013 for the ensuing ten years on a subregional basis, reflecting changes in the broader U.S. economic outlook looking forward in each of the five years.

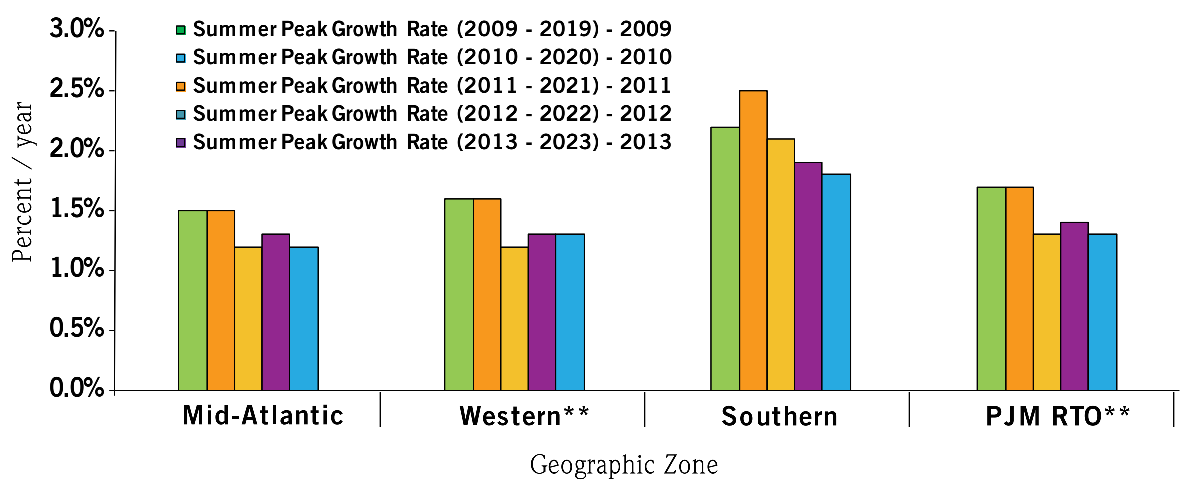
Figure 3.6: 10-Year Summer Peak Load Sub-Regional Growth Rates – 2012 vs 2013*



*** NOTE**

Figure 3.6*: The 2012 Western and PJM RTO values include both ATSI and DEO&K. The 2013 Western and PJM RTO values include ATSI, DEO&K and EKPC.

Figure 3.7: Annual Summer Peak Load Sub-Regional Growth Rate Comparison: 2009 through 2013**



**** NOTE**

Figure 10:** PJM's load report for 2009 did not include ATSI in Western and PJM RTO. PJM's 2010 Load Report does include ATSI in Western and PJM RTO values. PJM's 2011 and 2012 forecasts include ATSI and DEO&K in Western and PJM RTO values. PJM's 2013 forecast includes ATSI, DEO&K, and EKPC in Western and PJM RTO values.

3.3: Demand Resources

PJM's load forecast model produces a 15-year forecast assuming normal weather for each PJM zone and the RTO. The model uses anticipated economic growth and weather conditions to estimate growth in peak load, as outlined in PJM Manual M19, "Load Forecasting and Analysis", available on PJM's website via the following URL: http://www.pjm.com/~/media/documents/manuals/m19.ashx.

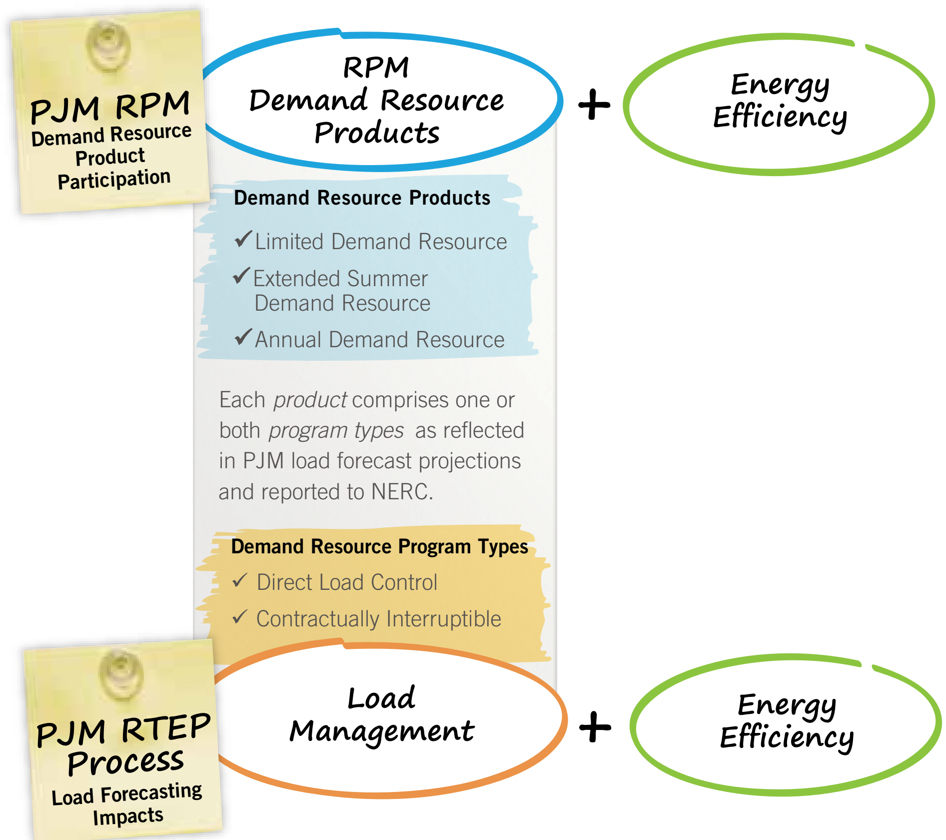
As part of load forecast development, PJM uses the results of its forward capacity auctions to adjust the base, unrestricted load forecast to account for Demand Resources and Energy Efficiency. This peak load forecast is then used in the development of RTEP power flow models as discussed above. Thus the status and availability of demand resources can have a measurable impact on the assessment of future system conditions that drive the need for new transmission to meet load-serving responsibilities.

As **Figure 3.8** shows, PJM RPM auction activity clears both demand resource products and energy efficiency programs. From a markets perspective, Limited Demand Resource, Extended Summer Demand Resource and Annual Demand Resource products comprise one or more program types: Direct Load Control, and Contractually Interruptible. PJM uses these program types in load forecasting terms to comply with NERC load management reporting requirements.

Demand Resource Products

Both existing and planned demand resources may participate in RPM Auctions, provided the resource resides in a party's portfolio for the duration of the delivery year. Requirements for each demand resource product are summarized in terms of

Figure 3.8: Demand Resource Definition



customer response characteristics in **Table 3.3** and are more fully described in PJM Manual M18, "PJM Capacity Market" accessible from PJM's website via the following link: http://pjm.com/~/media/documents/manuals/m18.ashx.

Load Management

At the customer level, load management is the ability to reduce metered load one of two ways: (1) manually by the customer, after a request from the resource provider or agent that holds the load management rights; or, (2) automatically in response to a communication signal from the resource provider that holds the load management rights (or agent in the case of Direct Load Control). PJM recognizes three types of load management:

- *Direct Load Control (DLC)* – Load management which is initiated directly by a Customer Servicer Provider (CSP) market operations center to non-interval metered sites via communication signal to cycle equipment. Air conditioner and water heater cycling is an example of direct load control.
- *Firm Service Level (FSL)* – Load management achieved by a customer that reduces load to a pre-determined level (the Firm Service Level), initiated upon notification from a CSP's market operations center
- *Guaranteed Load Drop (GLD)* – Load management achieved by a customer that reduces load by a pre-determined amount (the guaranteed load drop) when compared to the amount the customer would have consumed, initiated upon notification from a CSP's market operations center

Direct Load Control, Firm Service Level, and Guaranteed Load Drop program products are differentiated by various parameters including physical limitations of equipment, cycling characteristics , means of communications and contractual limitations, as further described in PJM Manual, M18, "PJM Capacity Market," accessible from PJM's website via the following link: http://pjm.com/~/media/documents/manuals/m18.ashx.

Table 3.3: Demand Resource Product Requirements

Requirement	Limited Demand Resource	Extended Summer Demand Resource	Annual Demand Resource
Availability	Any weekday, other than NERC holidays, during June – Sept. period of delivery year	Any day during June- October period and following May of delivery year	Any day during delivery year (unless on an approved maintenance outage during Oct. - April)
Maximum Number of Interruptions	10 interruptions	Unlimited	Unlimited
Hours of Day Required to Respond (Hours in EPT)	12:00 p.m. – 8:00 p.m.	10:00 a.m. – 10:00 p.m.	Jun – Oct. and following May: 10 a.m. – 10 p.m. Nov. – April: 6 a.m.- 9 p.m.
Maximum Duration of Interruption	6 Hours	10 Hours	10 Hours

Table 3.4: Energy Efficiency and Load Management

	2013 Load Forecast Report					
	2013	2014	2015	2016	2017	2018
Mid-Atlantic						
a) Energy Efficiency	261	268	215	215	215	215
b) Load Management	6,067	7,059	6,411	6,411	6,411	6,411
Total Load Management and Energy Efficiency	6,328	7,327	6,626	6,626	6,626	6,626
Western						
a) Energy Efficiency	573	605	669	669	669	669
b) Load Management	3,969	5,849	6,904	6,904	6,904	6,904
Total Load Management and Energy Efficiency	4,542	6,454	7,573	7,573	7,573	7,573
Southern						
a) Energy Efficiency	7	51	7	7	7	7
b) Load Management	706	1,312	1,333	1,333	1,333	1,333
Total Load Management and Energy Efficiency	713	1,363	1,340	1,340	1,340	1,340
PJM RTO						
a) Energy Efficiency	841	924	891	891	891	891
b) Load Management	10,742	14,220	14,648	14,648	14,648	14,648
Total Load Management and Energy Efficiency	11,583	15,144	15,539	15,539	15,539	15,539

The 2013 Load Forecast load management components of demand resources are summarized in **Table 3.4** and **Table 3.5**.

Energy Efficiency

Energy efficiency resources comprise the installation of customer devices, equipment, processes and systems, that exceed established building codes, appliance standards or other relevant energy efficiency standards at the time of installation. Such resources must achieve a permanent, continuous reduction in electric energy consumption (during a defined period). And they must be fully implemented at all times during the delivery year, without any requirement of notice, dispatch, or operator intervention.

Existing or planned energy efficiency resources were eligible for participation in the RPM auctions starting with the 2011/12 delivery year. Guidelines for measurement and verification of energy efficiency resources are provided in PJM Manual 18-B, accessible from PJM's website via the following link: http://pjm.com/~/media/documents/manuals/m18b.ashx.

The 2013 energy efficiency components of demand resource are summarized in **Table 3.4**.

Table 3.5: Load Management Components*

	2013 Load Forecast Report					
	2013	2014	2015	2016	2017	2018
Mid-Atlantic						
a) Contractually Interruptible	5,206	6,198	5,550	5,550	5,550	5,550
b) Direct Control	861	861	861	861	861	861
Total Load Management	6,067	7,059	6,411	6,411	6,411	6,411
Western						
a) Contractually Interruptible	3,810	5,690	6,745	6,745	6,745	6,745
b) Direct Control	159	159	159	159	159	159
Total Load Management	3,969	5,849	6,904	6,904	6,904	6,904
Southern						
a) Contractually Interruptible	638	1,244	1,265	1,265	1,265	1,265
b) Direct Control	68	68	68	68	68	68
Total Load Management	706	1,312	1,333	1,333	1,333	1,333
PJM RTO						
a) Contractually Interruptible	9,654	13,132	13,560	13,560	13,560	13,560
b) Direct Control	1,088	1,088	1,088	1,088	1,088	1,088
Total Load Management	10,742	14,220	14,648	14,648	14,648	14,648

*** NOTE**

Table 3.5:

- This forecast represents the amount of demand resources cleared in RPM auctions.
- Winter load management is equal to contractually interruptible.
- Contractually interruptible load equals firm service level and guaranteed load drop.

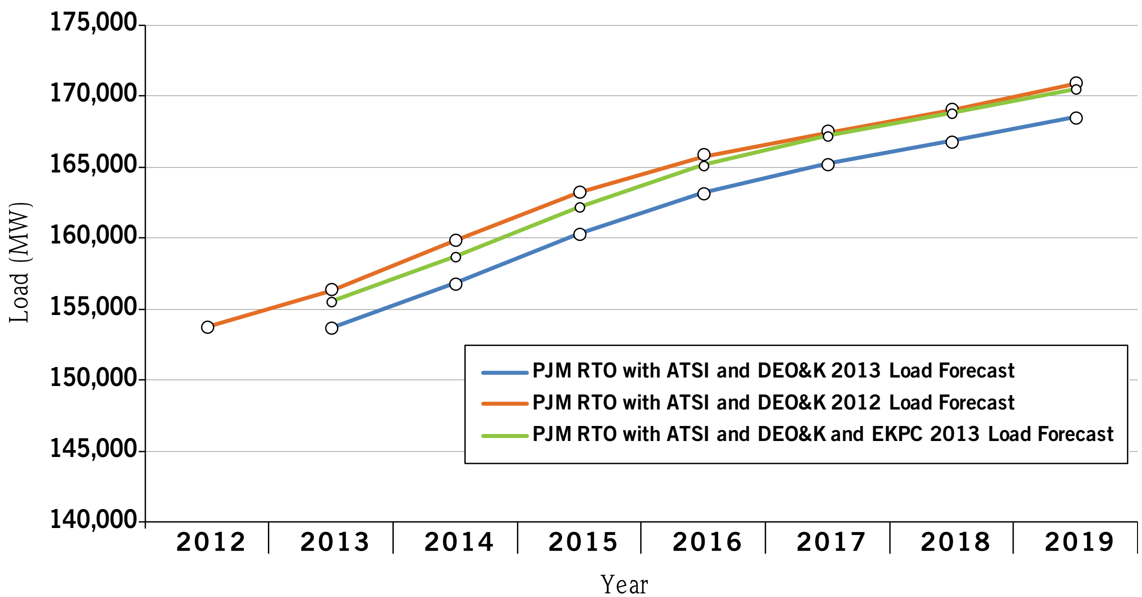
Demand Resource as Alternative to System Expansion

Demand resource programs across PJM have emerged under the aegis of various state initiatives. Sound planning practices, though, require PJM to ensure reliability such that the system effects of load management are only considered once they have cleared an RPM three-year-forward capacity market auction and satisfied all related, attendant obligations. Demand resources can defer the need for new generation and transmission resources. PJM actively encourages the development of such programs and integration into the capacity market. PJM participates actively in a number of stakeholder forums in order to encourage further development of demand resources.

3.4: 2018 Power Flow Base Case Load Bus Modeling

PJM's 2013 RTEP baseline analysis and retools conducted for 2014 through 2017 are based on the 2013 PJM Load Forecast Report. As summarized earlier, PJM's January 2013 load forecast covered the 2013 through 2028 planning horizon. From a power flow modeling perspective, the 2018 summer peak from that January 2013 forecast – at an overall RTO demand of 168,813 MW – was the basis for developing PJM's 2018 base case power flow model bus loads. Doing so will reflect that PJM now projects its RTO summer normalized peak to grow 1.3 percent annually over the next 10 years, shown in **Figure 3.9** in terms of megawatt load level, down from 1.4 percent annually in the 2012 forecast.

Figure 3.9: 10-year Summer Load Forecast Comparison: 2012 and 2013



Translating Zonal Load Forecasts to Bus Loads

As a starting point, in order to develop its base case PSS/E power flow model, PJM assigns zonal load from its January forecast to individual zonal buses according to ratios of each bus load to total zonal load; ratios are supplied by each transmission owner. Specifically, for load deliverability studies, zonal load is modified to account for load diversity, generally lowering the overall peak load in each area given that peak loads in different geographical areas happen at different times, i.e., are "non-coincident."

Retool Analyses

PJM's 2013 RTEP process includes retool analyses 2014, 2015, 2016 and 2017 baseline analyses which were conducted as part of PJM's 2009, 2010, 2011 and 2012 RTEP analyses, respectively. Those analyses were based on the original 2009, 2010, 2011 and 2012 load forecasts for 2014 through 2017, respectively.

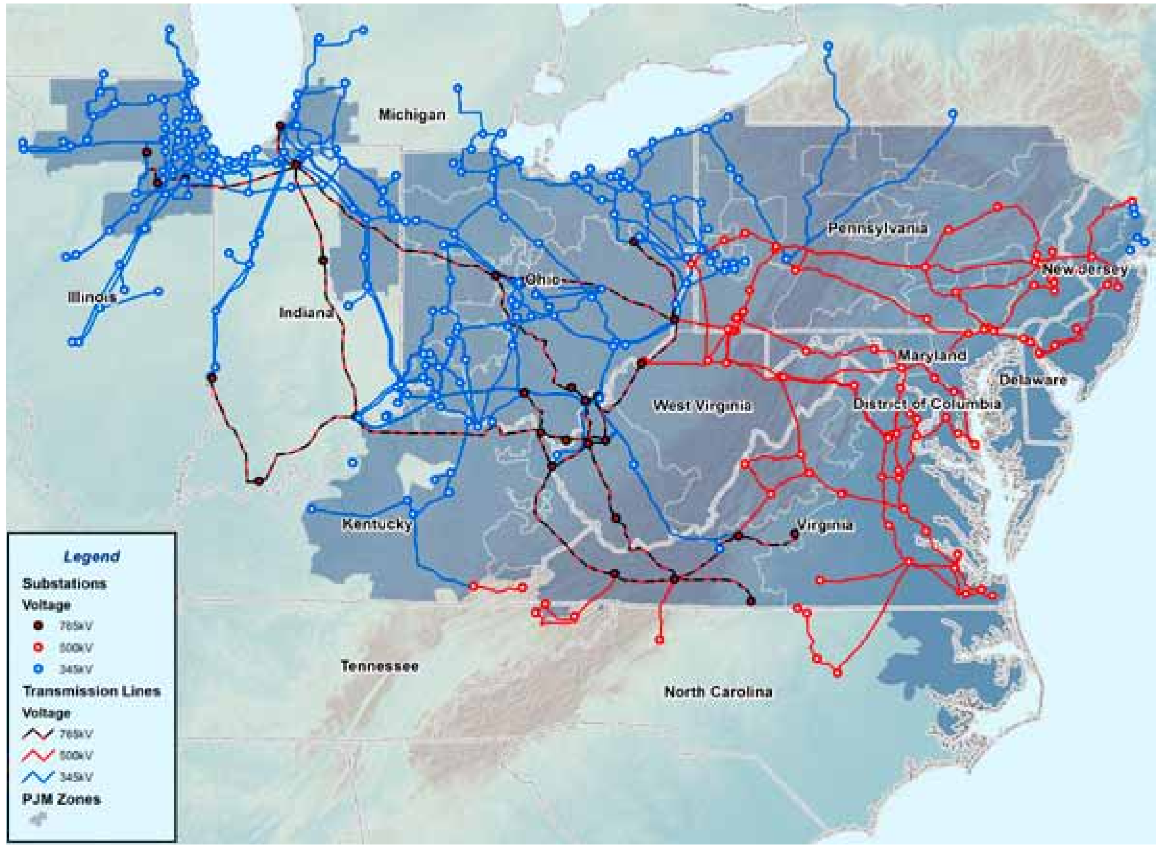
Section 4 – Topology, Generation and Interchange

4.1: 2018 Model Year Topology

PJM has developed a 2018 study year RTEP power flow base case consistent with established practice. To do so, PJM has updated its 2017 study-year case used in the 2012 RTEP process to reflect subsequent updates to generation, bus load and interchange information as well as all RTEP upgrades approved by the PJM Board through December 31, 2012. PJM then coupled this model with the Eastern Interconnection Reliability Assessment Group's (ERAG) 2018 series base case in order to model adjoining power systems.

The 2018 study year model also fully incorporates American Transmission Systems Inc. (ATSI) which integrated with PJM on June 1, 2011 and Duke Energy Ohio and Kentucky (DEO&K) which integrated on January 1, 2012. In addition, Eastern Kentucky Power Cooperative (EKPC), which integrated on June 1, 2013, has also been incorporated into PJM RTEP planning models and analyses. For perspective, PJM's backbone transmission system is shown on **Map 4.1**.

Map 4.1: PJM Backbone Transmission System



*** NOTE**

Additional information regarding the ERAG can be found on their website via the following link: https://www.rfirst.org/reliability/easterninterconnection reliability assessmentgroup/Pages/default.aspx.

Status of PJM RTEP Backbone Transmission

Transmission upgrades approved by the PJM Board through December 31, 2012, and expected to be in service by June 1, 2018, have been modeled in PJM's 2018 study year power flow base case. The specific status of approved backbone transmission lines not yet in-service is summarized below:

Susquehanna to Roseland

The Susquehanna-Roseland 500 kV line (Susquehanna-Lackawanna-Hopatcong-Roseland) – shown on **Map 4.2** – has a required in service date of June 1, 2012. Regulatory process delays have pushed the expected in-service out to June 1, 2015.

The line was approved by the Pennsylvania Public Utility Commission in February 2010 and by the NJ BPU in April 2010. In October 2012, the line received final approval from the National Park Service (NPS) who issued a Record of Decision on October 2, 2012 affirming the route chosen by PP&G and PSE&G; the NPS issued a Special Use (Construction) Permit on December 12, 2012. PJM will continue to operate to double circuit tower line limits in real-time operation until the new line is placed in-service. The Hopatcong - Roseland segment of the project is presently expected to be in service by June 1, 2014.

Mount Storm-Doubs

2011 RTEP analysis identified a required in-service date for the Mount Storm-Doubs line rebuild of June 2020 – shown on **Map 4.2**. However, recognizing the urgency of upgrading these aging facilities, Dominion and First Energy have indicated their intention to complete this reconductoring project by June 1, 2015. To that end, the capacity of the rebuilt line – with a rating 65 percent higher than the original – will be reflected in PJM's 2015, 2016, 2017 and 2018 power flow case modeling.

4.2: Generation and Case Lock-down

During annual case development process, PJM establishes a lock-down date early in the calendar year to determine what generation will be modeled in RTEP cases given each generator's status on that date. In addition to existing generating resources presently in-service, all generators expected in service by June 1, 2018 have been modeled, together with associated network and attachment upgrades.

Initially, PJM models each generator at its "Pmax" then uniformly scales all generation until its matches the load plus interchange plus losses. "Pmax" represents the maximum amount of power that PJM could expect it produce under peak load conditions. Pmax for an existing generator equals its level of Capacity Injection Rights (CIRs). Queued generators with ISAs seeking capacity status are modeled this way as well. For units – or portions of units – that have or are seeking "energy only" status, Pmax is set at the energy level for which they have been approved. Capacity Interconnection Rights (CIRs) quantify the power that a generator is permitted to deliver to PJM at a specified bus enabling that unit to participate in PJM's capacity market. CIRs are unit specific and granted in a quantity commensurate with the megawatt (MW) size identified in a generator's interconnection request and Interconnection Service Agreement (ISA), so long as the generator pays for any RTEP network upgrades required to ensure deliverability of that power to PJM load. PJM grants CIRs to the generation developer upon completion of necessary Regional Transmission Expansion Plan (RTEP) network upgrades to resolve North American Electric Reliability Corporation (NERC) reliability criteria violations.

ISA and FSA Generation – Permitted Case Statuses

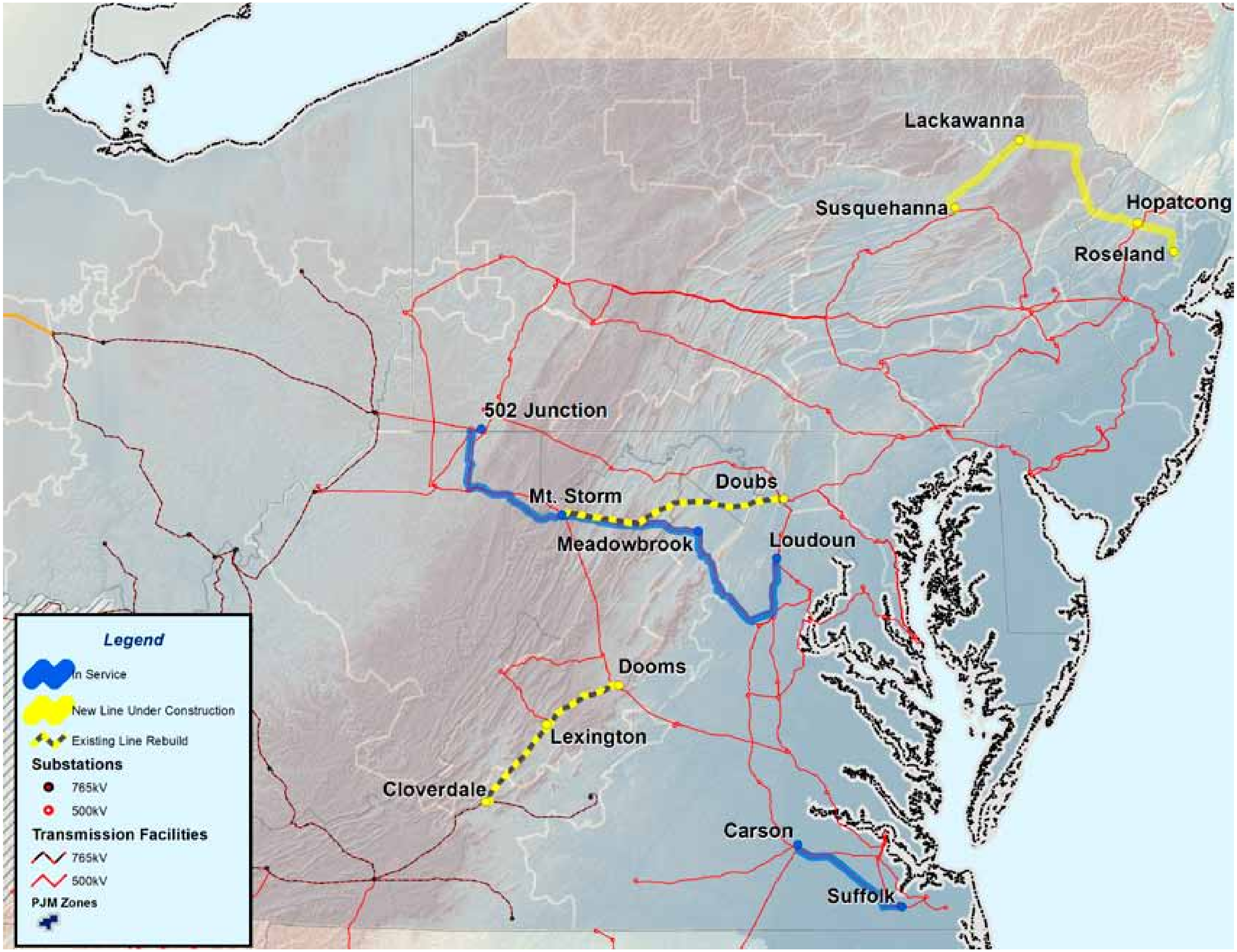
Executed FSA level queued projects are initially modeled offline in power flow cases. However, when existing and ISA level generation is not enough to meet load plus system real megawatt losses plus firm interchange, then FSA units are turned on in the case and dispatched accordingly. ISA generation that is not suspended is allowed to contribute to and back off transmission facilities experiencing reliability violations. PJM's 2018 "machine list" containing all generation modeled, can be found in **Appendix 1**.

Any project that has an executed Facilities Study Agreement (FSA) or signed ISA is modeled. Queued projects that have cleared an RPM auctions are also modeled. Projects that have withdrawn from PJM's interconnection queue are not modeled. **Map 4.4** shows the geographic scope of ISA and FSA generators modeled in PJM's 2018 RTEP case, per **Appendix 2**.

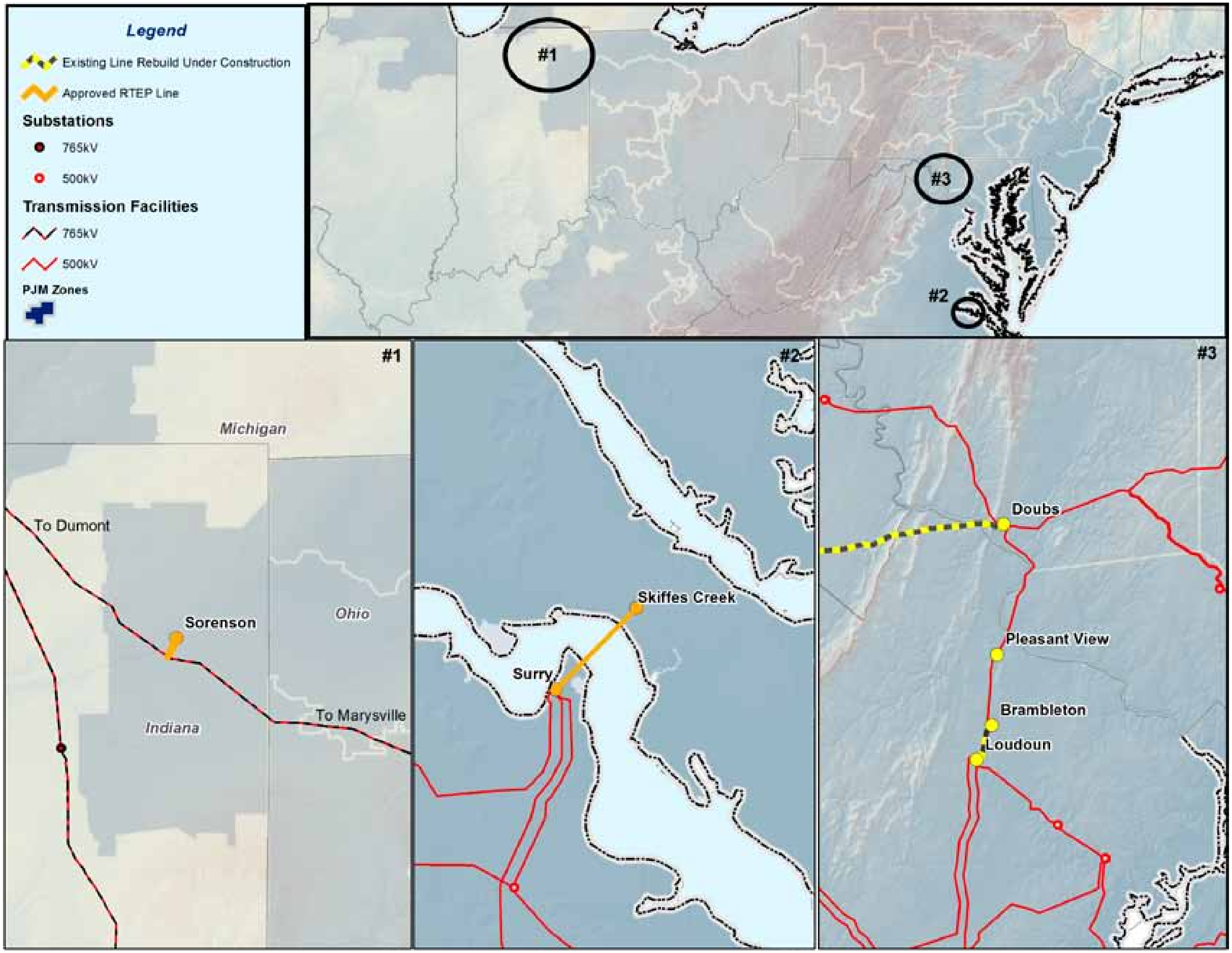
Generator Deactivations

Generators owners that have formally announced that their unit will deactivate by June 1, 2018 and have been studied by PJM are modeled in accordance with the outcome of those studies as of the lock-down date, including the need for any attendant RTEP upgrades to permit deactivation. In accordance with the case creation process documented in PJM Manual 14B, these units are modeled off-line and then fully removed from the model one year after their actual deactivation date.

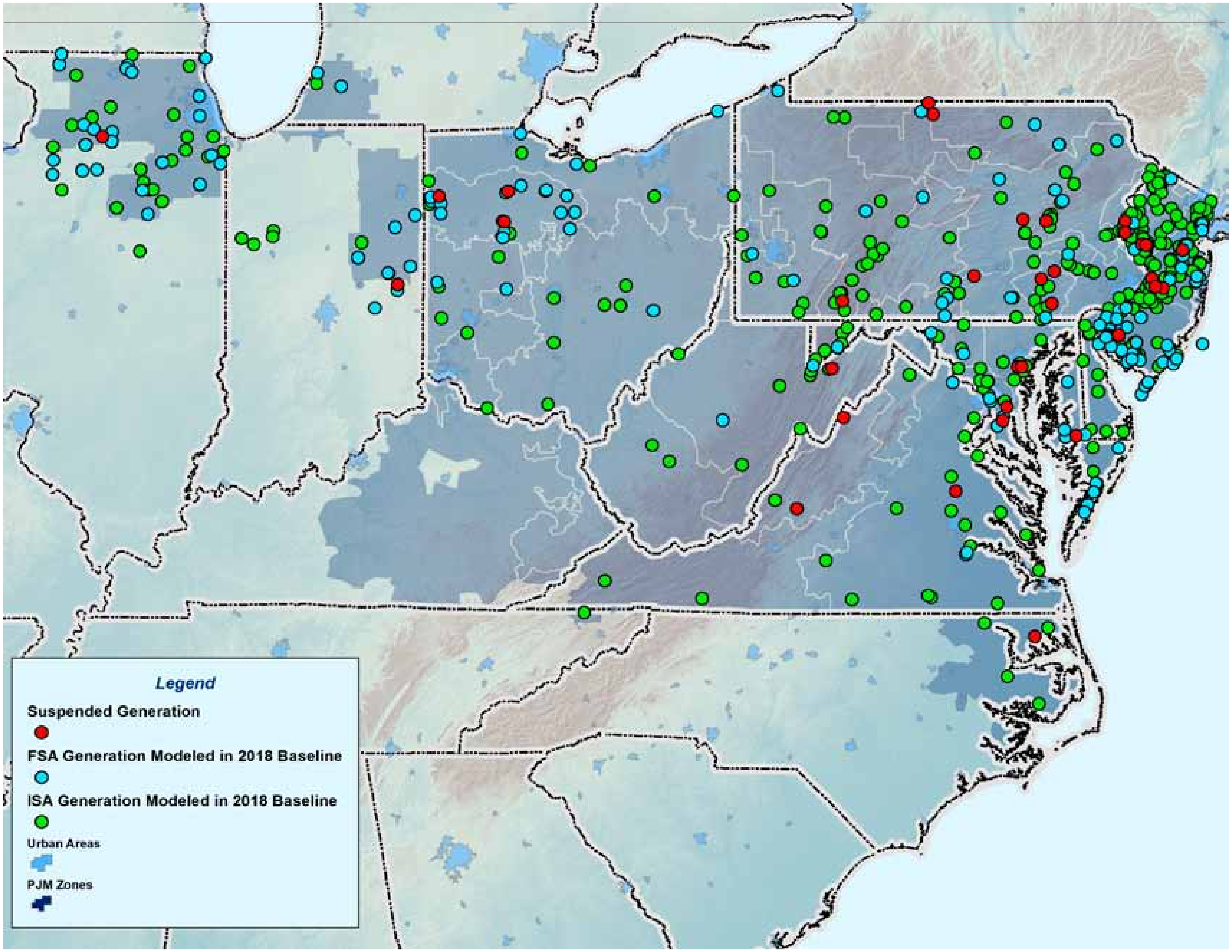
Map 4.2: Approved PJM Backbone 765 and 500 kV facilities – Over 50 Miles



Map 4.3: Approved PJM Backbone 765 and 500 kV Facilities – Under 50 Miles



Map 4.4: ISA/FSA Units Modeled in 2018 RTEP Power Flow Base Case

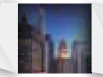


4.3: Interchange and Firm Transmission Service

PJM models interchange and firm transmission service by comparing ERAG case contractual interchange with PJM OASIS Long-Term Firm Transmission Service values. Consistent with established practice, differences are reconciled by scaling both PJM and external system generation. Power flow case 2018 interchange values are shown in **Table 4.1** and reflect the integration of Eastern Kentucky Power Cooperative (EKPC) on June 1, 2013.

Table 4.1: 2018 RTEP Interchange Table

From	To	Total
PJM	NYIS	2,277
PJM	OVEC	-2,257
PJM	CIN	-343
PJM	IPL	50
PJM	MECS	200
PJM	WEC	30
PJM	CPLE	-227
PJM	DUK	-50
PJM	TVA	6
PJM	AMIL (AMRN)	-640
PJM	LGEE	-309
PJM	ALTW	264
PJM	MEC	974
PJM	ALTE	140
Total		115



Section 5 – 2013 Baseline Analyses - Scope

5.1: NERC Planning Criteria

The Energy Policy Act of 2005 (EPAct 2005) created a Federal compliance and enforcement process for mandatory reliability standards, to be overseen by FERC. Pursuant to EPAct 2005, FERC designated NERC as the Electric Reliability Organization for the United States. Mandatory compliance with NERC Reliability Standards began on June 1, 2007. Compliance is mandatory, and penalties for violation of FERC approved NERC Reliability Standards may be as high as $1 million per violation per day. PJM's RTEP process rigorously applies NERC Planning Standards through the application of a wide range of reliability analyses – including load and generation deliverability tests – applied over both short-term and long-term planning horizons. PJM documents all conditions where the system did not meet applicable Reliability Standards and identifies system reinforcements required for compliance. Estimated costs and lead times are also developed in collaboration with transmission owners.

NERC Bulk Electric System (BES) Definition

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

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

The RFC definition of BES excludes:

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

Given this BES definition, PJM conducts reliability analyses to ensure compliance with NERC standards TPL-001 through TPL-004, each of which comprises one or more categories of facility contingencies, as shown in **Table 5.1**.

NERC Category A

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

NERC Category B

Also known as the N-1, or single contingency criteria, this Reliability Standard requires that the BES be tested following the loss of a single generator, transmission circuit or transformer, per NERC Reliability Standard TPL-002. In some cases, where the physical design of connections or breaker arrangements results in the outage of more than the faulted facility when the fault is cleared, the additional facilities are also outaged as a single event. If an existing relaying configuration is designed to remove more than one facility at the same time, multiple elements may be removed from service. Facilities are identified which have post contingency flows equal to or higher than 100 percent of the applicable emergency rating. In addition, voltages are monitored for compliance with existing voltage limits specified by PJM Operations in Manual M-03, accessible from PJM's website via the following link: http://www.pjm.com/~/media/documents/manuals/m03.ashx.

NERC Category C

This Reliability Standard requires that the BES be tested for the loss of multiple facilities, as specified in NERC Reliability Standard TPL-003, for example, loss of a double circuit tower line or a substation bus. In addition, NERC Reliability Standard TPL-003 requires all Category B contingencies to be simulated followed by manual system adjustments, followed by another Category B contingency to ensure the system remains within applicable limits for NERC Category C3 contingencies. This is commonly referred to as the N-1-1 criteria. Facilities are identified which have post contingency flows equal to or higher than 100 percent of the applicable emergency rating. In addition, voltages are monitored for compliance with existing voltage limits specified by PJM Operations in Manual M-03, accessible from PJM's website via the following link: http://www.pjm.com/~/media/documents/manuals/m03.ashx.

Table 5.1: NERC Criteria Reference Table

Standard	Category	Contingencies
TPL-001	A	All Facilities in Service
TPL-002	B	Fault with Normal Clearing – Loss of all Facilities Associated with a Single Contingency
TPL-003	C1	Bus Section Faults
	C2	Breaker Failure
	C3	Fault with Normal Clearing Followed by Re-Dispatch Followed by a Second Fault with Normal Clearing (N-1-1 Contingency)
	C5	Multiple Circuit Tower Line
TPL-004	D	Extreme Events

NERC Category D

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

External Contingencies

As part of developing the contingencies for the 2013 RTEP, PJM coordinated external system contingencies with its neighboring entities. As a result of this coordination, PJM now studies over 8000 external category B contingencies, and 5000 external category C contingencies from all neighboring Planning Coordinators. These contingencies include additional facilities which may electrically impact PJM facilities.

5.2: Comprehensive Analysis

The scope of 2013 baseline analyses will examine base case thermal and voltage conditions, under load deliverability and generation deliverability test conditions, common mode contingencies, short circuit duties and system stability as well as light load levels. Contingency analysis includes all PJM bulk electric facilities (BES) facilities, all other lower voltage facilities operated by PJM, and critical facilities in systems adjoining PJM, including tie lines between systems. RTEP analyses observe the same thermal and voltage limits specified by PJM Operations, per PJM Transmission Operations Manual M-3, available on PJM's website via the following URL: http://www.pjm.com/documents/manuals.aspx.

Baseline thermal and voltage analysis evaluates all BES facilities for compliance with NERC Category A (TPL-001), Category B (TPL-002) and Category C (TPL-003) events, including the following:

- Over 8,400 TPL-002 category B contingencies, including contingencies involving the loss of facilities in neighboring systems.

- Over 7,500 TPL-003 category C contingencies, including contingencies involving the loss of facilities in neighboring systems.
- The N-1-1 NERC category C3 analysis considers each possible combination of category B contingencies, a total of over 73,000,000 combinations.

In addition, PJM's contingency set also includes single contingencies comprised of non-BES transmission elements and a limited set of multiple facility contingencies involving non-BES facilities. Consistent with NERC standard TPL-004, a number of extreme events including those judged to be critical from an operational perspective will also be tested.

Near-Term Analysis (2018)

PJM near-term analysis comprises a five-year-out baseline study as well as retool studies for years one through four. This comprehensive assessment determines the ability of the PJM system to meet all applicable reliability planning criteria.

- *NERC Planning Standards:* http://www.nerc.com/
- *PJM Reliability Planning Criteria* as contained in Manual M14B Attachment G*:* http://www.pjm.com/documents/manuals.aspx
- *Transmission Owner Reliability Planning Criteria* as contained in their respective FERC 715 filings and accessible from PJM's website via the following link: http://www.pjm.com/planning/planning-criteria.aspx

Identifying Violations

PJM is required to apply NERC Reliability Standards in its planning process. The NERC Reliability Standards specify a wide range of reliability tests that must be applied over both near-term (years one to five) and long-term (years six to ten) planning horizons. Violations of these standards in either the near-term or long-term planning horizons can form the basis for PJM directed baseline transmission solutions. All reliability criteria testing procedures employed in the development of the RTEP include detailed assumptions regarding load levels, transfer levels and generation patterns. The tests are based on these documented procedures and assumptions and violations are identified when limits are exceeded.

Monitored Facilities

Baseline RTEP analyses monitor all PJM BES facilities – totaling over 20,000 – as modeled in power flow cases. A set of lower voltage, non-BES facilities as monitored by PJM Operations is also monitored in PJM planning studies. In addition, lines to adjoining systems as well as specifically identified MISO facilities are also monitored. In general, though, Reliability analyses of neighboring systems are conducted under established interregional planning processes.

Developing RTEP Upgrade Transmission Solutions

Once NERC reliability criteria violations are identified PJM works with all impacted parties to develop transmission plans to solve those violations. Otherwise, left unsolved, they could lead to operational problems and loss of service to customers. Potential upgrade solutions are reviewed with PJM stakeholders throughout the RTEP process for their feasibility, impact and costs. This process culminates in a single recommended plan – one RTEP – for the entire PJM region. Consistent with established practice, PJM submits individual elements of the plan to the PJM Board throughout 2013 for consideration and approval. PJM Board approval then binds transmission owning utilities to construct the approved upgrades and new transmission facilities.

Long-Term Planning (2028)

PJM's RTEP process 15-year planning horizon exceeds the scope of that required by NERC criteria and permits PJM to identify potential reliability criteria violations, the transmission solutions for which may require longer implementation lead times. Fifteen year forward results are reviewed to identify violations that occur for multiple deliverability areas or multiple or severe violations clustered in a specific area. Doing so allows PJM to determine if larger-scale, longer lead-time solutions can be identified to address groups of violations collectively.

Specifically, PJM's 2013 RTEP process will examine 2015 through 2028. Consistent with established practice, analyses included normal system, single and multiple contingency analysis. Generator deliverability and load deliverability procedures establish the critical system test conditions, discussed in **Section 5.3**.

Load forecasts for years 2018 through 2028 from the 2013 PJM Load Forecast Report will be used to develop load growth scaling factors for each of the most highly loaded flowgates in each year. Linear DC scaling factors will then be applied to calculate flowgate loadings. This type of analysis identifies any clusters of violations for which a more robust transmission solution than a set of multiple, individual upgrades, to address the near term violations in study year 2018. PJM also studies light load conditions as discussed in **Section 5.5.**

5.3: Deliverability

Baseline analyses include load deliverability and generation deliverability tests, generally under peak load conditions. In its role as Transmission Planner, PJM uses deliverability criteria to define the critical system conditions under which bulk electric system facilities are tested for compliance with NERC standards.

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

Load Deliverability

The methodology requires that each locational deliverability area (LDA) under test be modeled at a higher than normal load level – 10 percent probability of occurring – with higher than normal internal generating unit unavailability. Load deliverability studies test the transmission systems capability to import sufficient power to meet a defined Capacity Emergency Transfer Objective (CETO).

Load deliverability tests assess Category A and Category B contingencies both in baseline studies and merchant transmission interconnection requests, and are described in more detail in PJM Manual 14B, accessible from PJM's website via the following link: http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

Capacity Emergency Transfer Objective (CETO)

As part of load deliverability analysis, PJM first calculates a CETO for each locational deliverability area (LDA) shown in **Map 5.1**. The CETO value represents calculated for the load deliverability test is the import capability required for the area to meet a Loss-of-Load Expectation (LOLE) risk level of one event in 25 years. The risk refers to the probability that an LDA would need to shed load due solely to its inability to import needed capacity assistance during a capacity emergency. In other words, the transmission system is not robust enough to import sufficient energy during a capacity emergency.

PJM determines the CETO value for each LDA using a probabilistic model of the load and capacity located within each LDA. The model recognizes, among other factors, historical load variability, load forecast error, generating unit maintenance requirements and generating unit forced outage rates. A number of factors drive CETO value increases, including the following:

- LDA peak load increase
- LDA capacity resources decrease including generation, demand resource programs and energy efficiency
- LDA capacity resource availability factor decrease.

The reverse is also true for a decrease in LDA CETO values.

Capacity Emergency Transfer Limit (CETL)

A LDA CETL is impacted by changes in transmission system topology including the addition (or removal) of transmission facilities as well as by changes in the load distribution profile within a zone. The addition or retirement of generation facilities impacts power flows, and consequently CETL values as well.

Each CETL value is determined from the Load Deliverability power flow analysis and expresses the maximum megawatt that an LDA can import under specified peak load conditions.

Reliability – Thermal Analysis

A thermal overload occurs on a BES facility if flow on that facility exceeds 100 percent of one of the following:

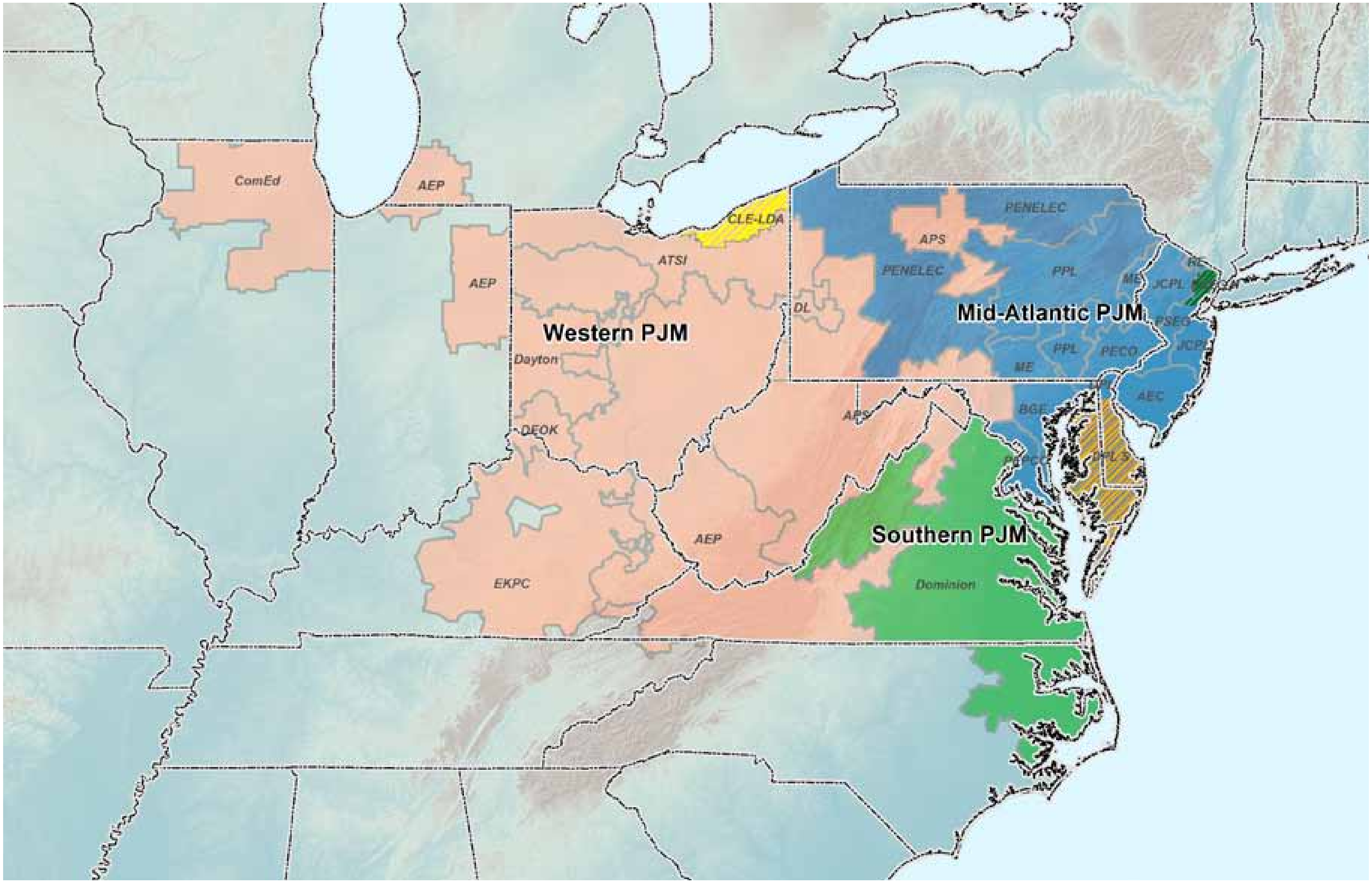
- The facility's normal rating with all facilities in service (i.e., NERC Category A)
- The facility's emergency rating following the loss of a single facility (i.e., NERC Category B)
- The facility's emergency rating following the loss of multiple facilities under a common mode contingency (i.e., NERC Category C)
- The facility normal rating following an N-1 event to prepare for the next contingency and subsequent system adjustments.

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

Generator Deliverability

The generation deliverability test ensures that the transmission system will not limit delivery of capacity resources, i.e., so that generation is not bottled when needed. The test considers the ramping impact of generators that are electrically

Map 5.1: PJM Locational Deliverability Areas



close to a particular flow gate as well as the ramping impact of queued generation that is electrically further away.

Generator deliverability testing ensures sufficient transmission capability to export generation capacity in excess of forecasted peak load from an area to the aggregate of PJM load.

The Generator Deliverability Testing Procedure is used to assess Category A and B contingencies as part of baseline analysis and as part of interconnection request studies, as described in PJM Manual 14B, accessible from PJM's website via the following link: http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

NERC Category C (TPL-003)

Under this Reliability Standard – commonly referred to as the N-1-1 criteria – PJM tests the transmission system for the loss of multiple facilities, for example, the loss of two single elements of the system. Standard TPL-003 requires the simulation of all Category B contingencies be followed by manual system adjustments, then followed by another Category B contingency to ensure the system remains within applicable thermal and reactive limits.

PJM examines over 73,000,000 N-1-1 combinations. Facilities are identified which have post contingency flows equal to or higher than 100 percent of the applicable emergency rating.

Voltages are monitored for compliance with existing voltage limits specified by PJM Operations in Manual M-03, accessible from PJM's website via the following link: http://www.pjm.com/~/media/documents/manuals/m03.ashx.

RTEP upgrades are developed to solve criteria violations where the system failed to meet the applicable normal rating after the first contingency or the applicable emergency rating after the second contingency.

Common Mode Contingencies

As part of PJM's analysis of NERC Category C events, PJM performs studies to determine the impact of the loss of multiple facilities that share a common element or system protection arrangement. These include bus faults, breaker failures, double circuit tower line (DCTL) outages and stuck breaker events.

5.4: Reactive Analysis

Reactive analysis has emerged as a key transmission expansion driver over the past several years. Once driven largely by thermal criteria violations, growing load and increasing generator deactivations throughout PJM are yielding the need for additional reactive reinforcements to ensure adequate voltage levels to support power transfers.

2013 RTEP analysis will examine these system reactive impact trends further. NERC Reliability Standards require that a transmission system be stable and within applicable equipment thermal ratings and system voltage limits. PJM will assess system voltage levels under Category A, B and C contingencies to ensure system voltages will be within applicable limits and thus not violate NERC Reliability Standards.

If the voltage magnitude is outside prescribed limits or the change in voltage (voltage drop) following the loss of a BES element is greater than a specified amount, then system upgrades must be identified to solve the criteria violations.

Permissible voltage magnitudes and voltage drop percentages are determined based on operational conditions at each substation. PJM 500 kV voltage drop is limited at many 500 kV substations to 5 percent. Emergency voltage magnitude is limited to no lower than 0.97 per unit (i.e. 97 percentage of nominal). Voltage magnitude and voltage drop limits are also defined in more detail in PJM Manual M-03, "Transmission Operations."

Load Deliverability Context

Consistent with deliverability studies for thermal criteria violations, PJM's load deliverability testing methodology also evaluates compliance with reliability voltage criteria. Doing so ensures that the transmission system is able to deliver energy to an area experiencing a capacity deficiency. As part of this test, PJM establishes a CETO for each LDA, shown in **Map 5.1.** The CETO value is the amount of energy that the transmission system must be capable of delivering to the LDA being tested.

Power-Voltage (PV) Curves

To the extent that more refined analysis is required, PJM will examine system reactive performance through what is commonly called PV, or power-voltage, analysis. PV analysis allows system engineers to evaluate critical BES contingencies on system voltages as power transfers are increased across the transmission system or across a specific transmission facility. PV analysis can be used to show the existence of violations of NERC Reliability Standards, but can also be used to determine the

point at which the system becomes unstable.
In a PV analysis, voltage conditions at a substation are represented on a curve. This shows the effect that increasing power transfers on a transmission line or set of lines has on voltage levels at the substation. Typically, as more power is transferred, voltage levels deteriorate. The more abrupt the decline in voltage level, the more difficult the voltage problem is to control operationally. A PV curve depicts the megawatt transfer levels at which the voltage drop and voltage collapse violations are projected to occur. Voltage magnitudes are monitored at substations as system power transfers into an LDA increase.

PV curves show how increasing power transfers on a given line – often by only small amounts – can reach a critical point where further increases cause transmission system collapse, known as the steady state stability limit. PV analysis provides a much more rigorous examination of voltage collapse phenomena frequently foreshadowed by voltage magnitude and voltage drop results in load deliverability tests, tests intended to ensure that the transmission system is able to deliver energy to a portion of the system that is experiencing a capacity deficiency.

N-1-1 Voltage Analysis

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

5.5: Light Load Analysis

As summarized in **Table 5.2**, PJM conducts light load analysis at a load level reflecting fifty percent of the 50/50 summer peak demand forecast. Generation is modeled to reflect typical operating statuses based on unit type. Similarly, interchange levels are modeled to reflect a statistical average during light load periods as experienced in actual Operations in prior years. For areas adjoining PJM, load level, interchange and generation dispatch are also based on statistical averages for previous off-peak periods. Monitored flowgates include all BES facility contingencies maintained by PJM planning including those monitored by PJM Markets. Contingencies are tested for compliance with NERC TPL Category B and Category C (with the exception of C3 N-1-1 criteria.)

The specific technical procedures governing light load reliability criteria analysis can be found in PJM Manual 14, Appendix D2, accessible on PJM's website via the following URL: http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

5.6: Short Circuit Studies

PJM's 2013 RTEP process – consistent with prior years – will include short circuit analysis to determine if any bulk electric system (BES) breakers exceed their interrupting capability. Calculated single phase to ground and three phase fault currents are compared to breaker interrupting capability provided by transmission owners. All breakers having ratings less than the calculated fault currents are identified and necessary upgrades determined. BES transmission upgrades identified as part of PJM's 2013 RTEP process will include a range of power system elements including circuit breaker replacements to accommodate increased current interrupting duty cycles. Short circuit analysis is performed consistent with the following industry standards:

ANSI/IEEE 551-2006 – Governs the recommended practice for calculating short- circuit currents in industrial and commercial power systems, how circuit breaker short circuit current information is provided and how related power system equipment is used to sense and interrupt fault currents.

ANSI/IEEE C37.04-1999 – governs the rating structure for AC high-voltage circuit breakers and associated equipment.

ANSI/IEEE C37.010-1999 – governs AC high-voltage circuit breakers rated on a symmetrical current basis, taking into consideration reclosing duration, X/R ratio differences, temperature conditions, etc.

ANSI/IEEE C37.5-1979 – governs fault current calculation of AC high-voltage breakers that are rated on a total current basis.

Each of these standards is used jointly with transmission owners' methodologies as a basis to calculate fault currents on all BES breakers. By using these standards, single phase to ground and three phase fault currents are calculated and compared to the breaker interrupting capability, provided by the transmission owners, for each breaker within the PJM region. All breakers whose calculated fault currents exceed breaker interrupting capabilities are considered overdutied and reported to transmission owners for confirmation. All breakers are used in specific short circuit cases which help to identify the cause and the year breakers are likely to become overdutied.

One-year-out and five-year-out short circuit cases are developed. The one-year planning case consists of the current system in addition to all facilities planned to be in-service within the next year. The five-year planning case uses the one-year-out planning case as modified to include all system upgrades, generating resources and merchant transmission projects planned to be in-service within five years. The five-year-out planning case is consistent with the five-year PJM RTEP load flow base case.

5.7: Stability Studies

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

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

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

Table 5.2: Light Load Analysis Assumptions

Light Load Analysis Elements	Study Assumptions
Network Model	5-year-out base case
Load Model	Light Load level at 50% of a non-diversified forecasted 50/50 summer peak load, reduced by energy efficiency
PJM Base Generation Resource Capacity Factors (Modeled Online in Base Case Dispatch)	Nuclear at 100% Coal >= 500 MW at 60% Coal < 500 MW at 45% Oil at 0% Natural Gas at 0% Wind at 40% All other resources at 0% Pumped storage at full pump
MISO Base Generation Reserouce Capacity Factors (Modeled Online in Base Case Dispatch)	Wind at 100%
Interchange Values	Historical statistical averages during off-peak load periods.
Contingencies	NERC Categories A, B and C (except C3)
Monitored Facilities	All PJM market monitored facilities

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

NERC Category C3 – N-1-1 Stability Analysis – N-1-1 stability analysis is conducted in a manner similar to maintenance outage study for operational guidelines. An N-1-1 contingency pair is defined as a single line to ground (SLG) or 3-phase fault with normal clearing, manual system adjustments, followed by another SLG or 3-phase fault with normal clearing. In the NERC TPL standard, N-1-1 contingencies belong to Category C3. Manual adjustments after first (N-1) contingency are allowed to relieve any thermal or voltage violations for applicable ratings and/or to prepare for second (N-1-1) contingency. N-1-1 stability analysis is defined as a stability analysis for given N-1-1 contingency scenarios. For a given N-1-1 contingency scenario, the first (N-1) contingency is applied to a pre-disturbance base case. If the system is stable, a new operating point is computed and manual adjustments are made if necessary, and then stability is monitored following second (N-1-1) single contingency.

Because of the assumed long time delay (from a stability point of view) between two single contingencies, the N-1-1 stability analysis is similar to maintenance outage study for operational guidelines.

5.8: Transmission Relay Loadability Analysis

PJM's RTEP process also tests compliance with NERC Reliability Standard PRC-023-2. The Standard specifies that transmission loadability must not be limited by protective relay settings and not interfere with a system operator's ability to take remedial action to maintain system reliability. Delays must be set so that they reliably detect all fault conditions and protect the electrical network from those faults.

Firstly, as part of annual planning process activities, PJM produces an updated list of facilities to be monitored that are between 100 kV and 200 kV and fall under Requirements 1 through 5 in Attachment B of Standard PRC-023-2. That list is also to be provided to respective Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers as well. Having determined a list of facilities to be monitored, PJM then conducts power flow analyses out five years to identify any criteria violations. Additional information can be found in PJM Manual 14B, Attachment G, Section 10 accessible from PJM's website via the following link: http://www.pjm.com/~/media/documents/manuals/m14b.ashx.

5.9: Long-Term Planning

PJM's 15-year planning horizon exceeds that required by NERC criteria and permits PJM to identify potential reliability criteria violations the solutions for which may require longer implementation lead times. Fifteen year forward results are reviewed to identify multiple violations across multiple LDAs or multiple ones in a specific LDA. This allows PJM to determine if larger-scale, longer lead-time upgrades can be identified to address such clustered violations collectively. While no such clusters were identified as part of the 2012 RTEP cycle that warranted more robust solutions to existing planned upgrades, PJM will continue to monitor loading trends on these facilities in 2013 as well.

Study Years 2019 through 2028

Consistent with established practice, analyses will include normal system, single and common mode contingency analysis. Both generator deliverability and load deliverability procedures will be used to establish the critical system conditions for evaluation.

Load forecasts from the 2013 PJM Load Forecast Report will be used to develop load growth scaling factors for each of the highest loaded flowgates in each year. Linear DC scaling factors will then be used to calculate flowgate loadings for each year.

5.10: Generation Deactivation

Generator deactivations alter power flows that often yield transmission line overloads and, given reductions in system reactive support from those generators, can undermine voltage support.

90 Days Notice

Per FERC order, PJM cannot compel unit owners to remain in service. Unlike timelines associated with requests for interconnection, deactivation may take effect upon 90 days notice.

PJM receives generation deactivation requests on a continuing basis and maintains a public list online via the following URL: http://www.pjm.com/planning/generation-retirements.aspx. After a formal deactivation request is received, PJM conducts reliability studies to identify reliability criteria violations caused by the deactivation and develop transmission solutions to solve them. The scope of those reliability studies comprises thermal and voltage analysis under generator deliverability, Common Mode Outage, N-1-1 Category C and load deliverability analyses.

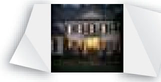
System expansion solutions may include upgrades to existing facilities, scope expansion for current baseline projects already in RTEP or the construction of altogether new BES facilities. In the event that an upgrade will not be in-service until after deactivation, PJM will implement operating procedures to manage constraints in real time or retain deactivating generators under the terms of reliability must run contracts.

5.11: Retool Analysis

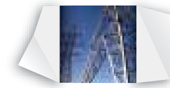
As part of this year's 2013 RTEP cycle PJM will review – as it does every year – transmission plans developed in earlier years to determine whether, as a result of changing assumptions, previously approved transmission upgrades are still required and, if so, whether they are still required in the year originally identified.

Frequent re-analysis using established methodologies also helps to identify and confirm chronic system weaknesses. When the same set of NERC Reliability Standard violations appear in several successive analyses – even if near-term load forecast and system topology changes cause the violations to appear earlier or later than previous analyses may have indicated - PJM then explores the repeated violations to develop an appropriate RTEP upgrade solution.

Planning is a dynamic process; system conditions change over time. Changing circumstances can drive the need to adjust assumptions used in planning studies and re-evaluate decisions made in previous planning cycles.



Section 6 – Interregional Planning Studies – Scope



6.1: Overview

Interregional planning is not new to PJM, having engaged in successful, collaborative studies for decades, many under the auspices of NERC. In recent years, PJM's responsibilities have grown in parallel with the evolution of broader organized markets and interest at the state and federal level in favor of greater coordination. FERC Order No. 1000 speaks to this very topic, as will additional RTEP Process white papers in 2013.

Each interregional study effort is conducted in accordance with a specifically defined scope and may include reliability analysis, stability analysis, transfer analysis, market efficiency analysis, short circuit analysis as well as generation and merchant transmission interconnection analysis. The development and maintenance of updated joint planning system models is necessarily a key element of all interregional study activities conducted jointly with the planning staffs of adjoining systems.

Interregional activities within PJM itself are coordinated with stakeholders through Planning Committee (PC), Transmission Expansion Advisory Committee (TEAC) and Markets and Reliability Committee (MRC) discussions. These committees provide opportunities to review and discuss input assumptions, scope documents and interim study results to surface issues and identify potential transmission facilities for additional consideration.

Geographical Scope

Under each interregional agreement, coordinated planning includes assessment of current operational issues to ensure that critical cross-border seams issues are identified and addressed before they impact system reliability or dilute effective market administration. Each agreement codifies the interregional planning process to be followed. This provides PJM and its neighbors – shown on **Map 6.1**– the governance structure, stakeholder forums and coordinated processes by which to address issues of mutual concern:

- Interregional impacts of projects to interconnect to the electric grid.
- Cross-border impacts of regional transmission plans.
- Opportunities for efficiencies at interregional seams.
- Solutions to reliability and congestion seam constraints.
- National and state public policy objectives that have interregional planning impacts.
- Increased power flow modeling accuracy within individual RTO planning processes through periodic modeling data and information exchange.

Public Policy

Interregional reliability and economic efficiency issues span large parts of the U.S. and comprise a key part of the broader public policy discussion around large scale integration of wind and other renewable resources. The growing integration of wind resources, often distant from load centers they serve, raises significant policy and operational issues regarding the transmission facilities required to connect the two. Making this a reality requires that fundamental policy questions be addressed: how much transmission should be built, where it should be built, when it should be built and how costs for it should be recovered.

Interregional Coordination Initiatives in 2013

PJM's RTEP process integrates interregional planning initiatives that have become increasingly more complex and expansive in light of emerging public policy issues and market dynamics. Interregional planning activities in 2013 will encompass continuing study efforts with systems across the U.S. Eastern Interconnection, as well as with Midcontinent Independent System Operator, ISO-New England, New York Independent System Operator and the North Carolina Transmission Planning Collaborative.

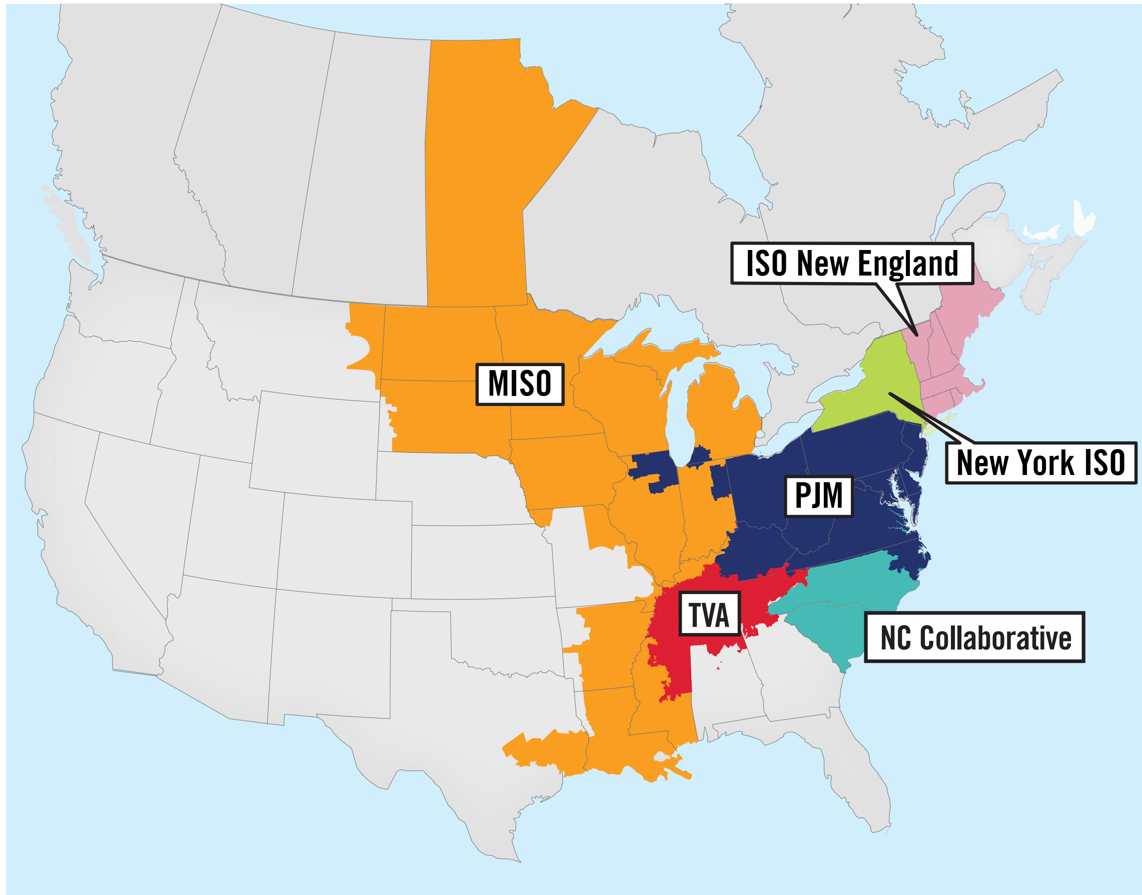
6.2: Eastern Interconnection Planning Collaborative

The Eastern Interconnection Planning Collaborative (EIPC) provides a forum to leverage existing regional planning processes and expertise in order to analyze the entire U.S. Eastern Interconnection. Formed in 2008, the goal of the EIPC has been to enhance Eastern Interconnection wide planning and analysis. Shortly after its formation, the EIPC submitted a proposal to the US Department of Energy (DOE) in response to its announced Request For Proposals to perform Eastern Interconnection wide transmission analysis.

In late 2009, the US Secretary of Energy announced the EIPC had been selected to receive $16 million from American Recovery and Reinvestment Act stimulus funds. The DOE also announced $14 million in funding would be awarded to the Eastern Interconnection States Planning Council (EISPC) to assist in developing a consensus process to identify renewable resources and other policy options for input to EIPC technical team analysis. In early 2010, the DOE completed a final scope as well as the terms and conditions for an agreement to proceed with the DOE award work. The funds were then used to conduct Phase I and Phase II work in 2011 and 2012 in accordance with the final scope. In late 2012, the EIPC completed a final scope for continued collaborative efforts in 2013 that will reflect two areas of concentration:

1. Gas-electric system interface study
2. Continuation of non-grant work

Map 6.1: PJM Interregional Coordination



Gas-Electric System Interface Study

In light of recent industry generation trends, the DOE has identified the need to conduct an Eastern Interconnection wide gas-electric system interface study. Funded by the DOE, this study will be conducted by the EIPC in 2013 with the assistance of an independent consultant. The study will be governed by the stakeholder process established as part of DOE Phase I and Phase II work. PJM markets staff will actively participate, providing input on study process and assumptions and feedback on results.

Continuation of Non-Grant Work

The EIPC stakeholder process for 2013 efforts will differ from the stakeholder process developed and utilized for EIPC's prior work in Phase I and Phase II. The continuation of EIPC efforts will be funded directly by participants and governed by a new regional-based stakeholder process. This provides an opportunity for greater consistency with the individual regional planning processes and methods of participants. The new stakeholder process will give regional parties a channel to provide input and feedback to EIPC in an effective and transparent manner. In addition, the EIPC stakeholder process will continue outreach to the Eastern Interconnection States Planning Council (EISPC) for its input as well.

In 2013 the EIPC will continue Phase I and Phase II work by concentrating on joint model development. EIPC participants will develop two future joint models to reflect their combined respective regional transmission plans for the 2018 and 2023 study years. The models will then be evaluated using reliability analysis to identify potential interregional violations and solutions for comparison with those identified in existing regional plans.

PJM will review EIPC results with the Transmission Expansion Advisory Committee (TEAC), Independent State Agencies Committee (ISAC) and the Organization of PJM States, Inc. (OPSI). This will provide PJM stakeholders the means to provide feedback in light of PJM's own RTEP.

6.3: North Carolina Transmission Planning Collaborative (NCTPC)

PJM will continue collaboration in 2013 on several efforts with the North Carolina Transmission Planning Collaborative (NCTPC), which includes Progress Energy Carolinas (PEC) and Duke Energy Carolinas (DEC). Given NCTPC's geographical scope and proximity, PJM will continue to provide updated power flow case data for NCPTC's own transmission system reliability studies, review analyses and results and provide feedback to the NCTPC as needed.

PJM and NCPTC are also considering a second joint interregional study to evaluate the potential reliability impacts of various generation resource expansion and transfer scenarios on the PJM, DEC and PEC systems. PJM and the NCTPC would collaborate to determine the input, scope and assumptions of the study and then move to conduct analysis and report results.

6.4: ISO-New England (ISO-NE) and New York ISO (NYISO)

PJM coordinated planning with ISO-NE and NYISO will continue on several fronts in 2013.

Production Cost Models

PJM efforts in 2013 with ISO-NE and NYSIO will continue to improve processes to coordinate and update interregional production cost modeling data. The process has evolved from a single region performing market simulations on a coordinated zonal production cost model to each region producing market simulations on a coordinated nodal production cost model. The development of a nodal production cost model marks a significant advance in data coordination and exchange among the three regions. Interregional efforts in 2013 will focus on comparing the market simulations from each region and using simulation results to improve the production cost model further. Each region's internal economic analyses will also benefit from these coordinated models

Cross-Border Impacts of Baseline Upgrades

PJM will also continue ongoing joint analysis to review the cross-border impacts of two PJM RTEP approved baseline upgrades, in accordance with the terms of the Northeastern ISO/RTO Planning Coordination Protocol. The scope of the two upgrades requires cutting-in new substations on the Homer City – Stolle Road 345 kV and Homer City – Watercure 345 kV lines. Both are tie lines to the NYISO and owned by New York State Electric & Gas Corporation (NYSEG). In 2013, PJM and NYISO will determine the scope of the system impact study, conduct analysis and jointly evaluate results.

Northern New Jersey Short Circuit Reliability Studies

PJM's 2012 RTEP short circuit analysis identified significant short circuit violations in the Northern New Jersey system. The analyses revealed the need for upgrade solutions to mitigate fault currents in excess of standard industry-available circuit breaker capabilities. In 2013, pursuant to PJM Board of Managers direction, PJM will continue to evaluate AC and DC upgrade solutions to address identified violations. PJM and NYISO will work jointly to assess potential upgrades, alternatives and their system impacts.

Northern Pass Transmission (NPT) Project

The NPT Project in ISO-New England encompasses a planned high-voltage DC transmission line between the ISO-NE and Hydro-Quebec systems. ISO-NE raised concerns that the project may have potential transient stability impacts on PJM due to system interactions of New England DC ties and New England AC system contingencies. PJM will conduct a stability analysis on a jointly coordinated model to evaluate transient fault conditions in the ISO-NE system and subsequent impacts on the PJM system due to the NPT Project. The analysis will focus concentrate on determining if faults in the ISO-NE system cause worse transient conditions in PJM than faults within PJM itself.

Joint ISO/RTO Planning Committee (JIPC)

The JIPC provides a forum for PJM, ISO-NE and NYISO to raise and discuss regional planning challenges of mutual concern, often driving the need for interregional assessments. Additional interregional coordinated studies in 2013 may examine such upgrade drivers as demand resources and solar resources and system contingencies that include the loss of major generating units.

6.5: Midcontinent Independent System Operator (MISO)

PJM is continuing coordinated planning activities with MISO in 2013 under the terms of the Joint Operating Agreement (JOA). Joint studies in 2013 will build on work completed in 2012 in which PJM and MISO gathered historical congestion settlement data on Market-to-Market and other border area flow gates. Based on a set of jointly developed metrics, a list of commonly congested flow gates has been identified for additional analysis in 2013.

A key aspect of the 2013 study process will include the development of a joint interregional production cost model for market efficiency simulations, marking the first time both regions will utilize a single, coordinated database. The study will examine 2017, 2022 and 2027 study years, focusing on the list of congested flow gates identified in 2012. In each model year, three generation expansion scenarios will be studied, each consistent with PJM's own previous RTEP studies.

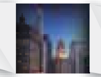
1. The first scenario will provide a base expansion perspective which for PJM will include only queued renewable-powered generation projects with an executed Facilities Study Agreement (FSA) or Interconnection Service Agreement (ISA). To the extent necessary, reserve requirement will be met with additional generation modeled in proportion to the location and resource technology of interconnection queue requests. In this first scenario, MISO will model sufficient renewable resources to satisfy their own internal states' RPS requirements – a standard MISO Transmission Expansion Plan (MTEP) assumption.

2. The second scenario from a PJM perspective will include, in addition to FSA and ISA queued generation, sufficient renewable resources to meet states' RPS requirements, all modeled on-shore, consistent with the methodology employed in PJM's 2012 RPS analysis. No transfers from MISO to PJM comprising renewable energy will be modeled. As in this first scenario, MISO will model sufficient renewable resources to satisfy their own internal state RPS requirement

3. The third scenario will model sufficient wind resources for both PJM and MISO to satisfy combined states' RPS requirements with approximately 40 percent of PJM's needs imported from MISO.

Designed to inform respective individual PJM and MISO regional planning processes, the first scenario will provide the basis for examining potential interregional upgrades to solve commonly congested flow gates on the combined PJM-MISO systems. Transmission upgrades will have to meet both PJM's and MISO's respective RTEP process criteria to be pursued any further

Scenarios two and three will provide PJM and MISO the opportunity to explore hypothetical future end-state generation expansion scenarios as driven by specific renewable-powered resource targets. To the extent that analyses are completed by the middle of 2013, PJM and MISO currently have planned a retool analysis based on updates to the interregional production cost model and other power flow model case assumptions. Proposed transmission upgrades may be re-evaluated and results communicated to stakeholders at that time.



Section 7 – 2013 Market Efficiency Analyses

7.1: Scope of Analysis

PJM's Regional Transmission Expansion Plan (RTEP) Process includes a Market Efficiency Analysis, the goal of which is to accomplish the following objectives:

1. Determine which reliability upgrades, if any, have an economic benefit if accelerated.

2. Identify new transmission upgrades that may result in economic benefits.

3. Identify economic benefits associated with modification to reliability-based enhancements already included in the RTEP that when modified would relieve one or more economic constraints. Such upgrades resolve reliability issues but are intentionally designed in a more robust manner to provide economic benefits in addition to resolving those reliability issues.

Economic benefits of proposed transmission projects can be created by mitigating congestion within production cost simulations of PJM's transmission and generation dispatch systems. The benefit metrics are determined by comparing future year simulation results of PJM's system, both without and with the proposed transmission enhancement. The set of metrics utilized and the methods involved with benefit determination are further described in Manual 14B Section 2.6 and Section 1.5.7 of PJM Operating Agreement Schedule 6.

PJM's 2013 Market Efficiency Analysis will evaluate transmission enhancements for their forecast economic value based on projections of their ability to relieve persistent congestion at locations throughout the PJM footprint.

Simulation Process

PJM Market Efficiency Analysis employs a market simulation tool that models an hourly security-constrained generation commitment and dispatch. In order to accomplish the market efficiency objectives discussed above, several base cases will be developed. The primary difference between these cases is the transmission topology to which the simulation data is mapped. The "as is" base case will be mapped to a 2012 transmission topology case and include significant upgrades which are expected to be in service by the end of 2013. The "as planned" base case will be mapped to a transmission system that includes all the approved PJM RTEP upgrades approved through the 2012 RTEP cycle.

By running and comparing results of multiple simulations with the same generator economics and operating constraints but with differing transmission topologies, an economic value of a transmission upgrade can be determined. Utilizing this basic technique while incorporating additional analysis allows PJM to perform the following tasks:

1. Collectively value the approved RTEP upgrades,

2. Evaluate if acceleration or modification of RTEP projects are economically beneficial, and

3. Evaluate if specific proposed transmission enhancements would be economically beneficial.

Additionally, sharing the transmission congestion results in the PJM base cases with stakeholders provides an expectation of potential conditions impacting the PJM market.

7.2: 2013 Market Efficiency Cycle

While the scope of the 2013 Market Efficiency Analyses remains essentially the same as in 2012, this year's analysis represents a transition year to reflect the second year of the 24 month RTEP cycle. As such, the distribution of study years will change but the same base process simulation database release used in 2012 will be used in creating the 2013 base cases. The base database will be modified to reflect updated key input assumptions for 2013.

Near-Term Simulations: 2014 and 2018 Study Years

By comparing the total simulation differences from the "as is" base case to the "as planned" base case for both 2014 and 2018 study years, PJM will be able to quantify the total transmission congestion reduction due to recently planned RTEP upgrades.

Similarly, comparison of the near-term "as-is" and "as-planned" simulations can identify constraints which may cause significant congestion and whether already planned upgrades may eliminate or relieve this congestion to the point that the constraint is no longer an economic concern. A comparison of these simulations can reveal if a particular RTEP upgrade may provide economic benefit that would make the upgrade a candidate for acceleration or expansion. For example, if a constraint causes significant congestion in the 2014 simulation but not in the 2018 simulation then the upgrade which eliminates this congestion in 2018 may be a candidate for acceleration. The benefit of accelerating this upgrade is then compared to the cost of acceleration before any recommendation can be made to the PJM Board.

Long-Term Simulations: 2017, 2020, 2023, and 2027 Study Years

To identify and quantify future transmission system congestion, market simulations will be conducted for study years 2017, 2020, 2023, and 2027. These simulations will use the 2017 RTEP "as-planned" transmission system topology and includes the significant RTEP projects approved through the 2012 RTEP cycle. This includes the backbone transmission projects depicted earlier in **Map 4.2** and **Map 4.3**.

Stakeholder Proposals

As part of the 2013 market efficiency cycle, PJM will continue to evaluate market efficiency proposals submitted by stakeholders to address congestion, observed both historically and in future year simulations.

These proposals will be evaluated with market efficiency simulations by comparing study year results both with and without the proposed transmission project. The projects will be compared in discrete study years to the "as planned" topology for the same annual periods. The key economic benefit measurements are determined for a 15-year period beginning at the expected project in-service date.

7.3: Benefit-to-cost Threshold Test

PJM will perform a benefit-to-cost threshold test to determine if market efficiency justification can be established for any transmission proposals that may be recommended to the PJM Board for RTEP inclusion. Market efficiency transmission proposals that have the potential to meet or exceed the 1.25 benefit-to-cost ratio threshold test are further assessed in order to examine its impact on system reliability. For projects with a total cost exceeding $50 million, the PJM Operating Agreement requires an independent review of project costs to ensure consistency in estimating practice and scope development.

The benefit-to-cost ratio is calculated by comparing the net present value of annual benefits determined for the first 15 years of the upgrade life to the net present value of the upgrade revenue requirement for the same 15-year period.

PJM's annual benefit calculation is weighted 70 percent to change in system production cost and 30 percent to change in net load energy payment. Change in system production cost comprises the change in system generation variable cost (fuel costs, variable operating and maintenance (O&M) costs, and emissions costs) associated with total PJM energy production. Change in net load energy payment comprises the change in gross load payment offset by the change in transmission rights credits.

PJM's RTEP market efficiency study process and the benefit-to-cost ratio methodology in particular, are described in Section 2 of PJM Manual 14B, PJM Region Transmission Planning Process, available on PJM's website via the following URL: http://pjm.com/~/media/documents/manuals/m14b.ashx.

7.4: Input Parameters

Prior to the initiation of 2013 PJM Market Efficiency Analyses, the PJM Transmission Expansion Advisory Committee (TEAC) and the PJM Board review key analysis input parameters, shown in **Figure 7.1**. These parameters include fuel costs, emissions costs, load forecasts, demand resource projections, generation projections, expected future transmission topology, and financial valuation assumptions. Simulation models now also include the East Kentucky Power Cooperative (EKPC) Zone which integrated with PJM on June 1, 2013.

Additional details are described in the proceedings of the PJM Transmission Expansion Advisory Committee (TEAC) available on PJM's website via the following URL link: http://www.pjm.com/committees-and-groups/committees/teac.aspx.

Transmission Topology

Market efficiency base case power flow models will be developed to represent (1) the 2014 "as-is" transmission system and (2) the expected system topology in 2017.

The 2014 as-is system topology will be derived from Eastern Interconnection Reliability Assessment Group (ERAG) Multi-Regional Modeling Working Group (MMWG) 2011 Series 2012 summer peak case. It will include significant upgrades which are expected to be in service by the end of 2013. The 2017 and later topology will be derived from PJM's 2017 RTEP base case,

*** NOTE**

PJM in collaboration with its stakeholders continues to discuss possible improvements to the components of the benefit-to-cost calculation as part of ongoing Regional Planning Process Task Force (RPPTF) discussions. Additional information on these proceedings is accessible from PJM's website via the following link: http://www.pjm.com/committees-and-groups/task-forces/rpptf.aspx.

including all upgrades identified as part of PJM's RTEP process up through and including those identified as part of the 2012 RTEP cycle. Specifically, the status of backbone lines – shown earlier in **Map 4.2** and **Map 4.3** – in market efficiency cases are summarized in **Table 7.1** for each of the 2013, 2014, 2017, 2018, 2020, 2023 and 2027 study year models.

Constraints to be Monitored

Specific transmission constraints will be modeled for each base topology. These include thermal constraints and reactive interface constraints. A representation of the event files that identifies the monitored constraints will be posted on PJM's website.

Monitored thermal constraints include facility and contingency elements selected by examining historical PJM congestion events, reviewing other PJM planning studies, or by their representation in the NERC Book of Flowgates.

PJM reactive interface limits are thermal limits derived from studying reactive conditions beyond which voltage violations may occur. The modeled interface limits are based on voltage stability analysis and a review of historical values. Modeled values of future-year reactive interface limits incorporate the impact of approved RTEP upgrades on the reactive interfaces.

Generation Modeled

Market efficiency generation models will include all existing in-service generation plus actively queued generation with an executed Interconnection Service Agreement (ISA), less planned generator deactivations that have given formal notification. Initial review of the market efficiency model indicates that PJM's installed reserve requirement

Figure 7.1: Market Efficiency Analysis Parameters

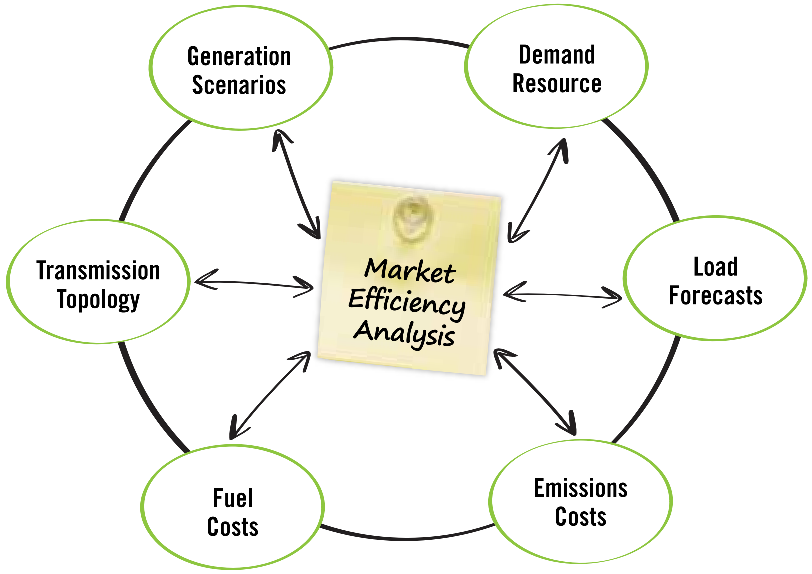


Table 7.1: Backbone Project Modeling - Market Efficiency Studies

Project	2013, 2014	2017 and Beyond
Jacks Mountain	No	No
Susquehanna - Roseland	No	Yes
Mt. Storm - Doubs Rebuild	No	Yes
Cloverdale - Lexington Rebuild	No	Yes
Lexington - Dooms Rebuild	No	Yes

will be met through 2019, as shown in **Figure 7.2**. In order to meet PJM's installed reserve requirement for study years 2020, 2023 and 2027 – 1,900 MW, 6,100 MW and 13,800 MW of additional generation will be added to the model, respectively. As shown in **Table 7.2**, additional generation will be added in proportion to the regional location and generation type of active generation projects without signed ISAs through Generation Interconnection Queue Y2.

Figure 7.2: Future Reserve Margin – 2013 Market Efficiency Analysis

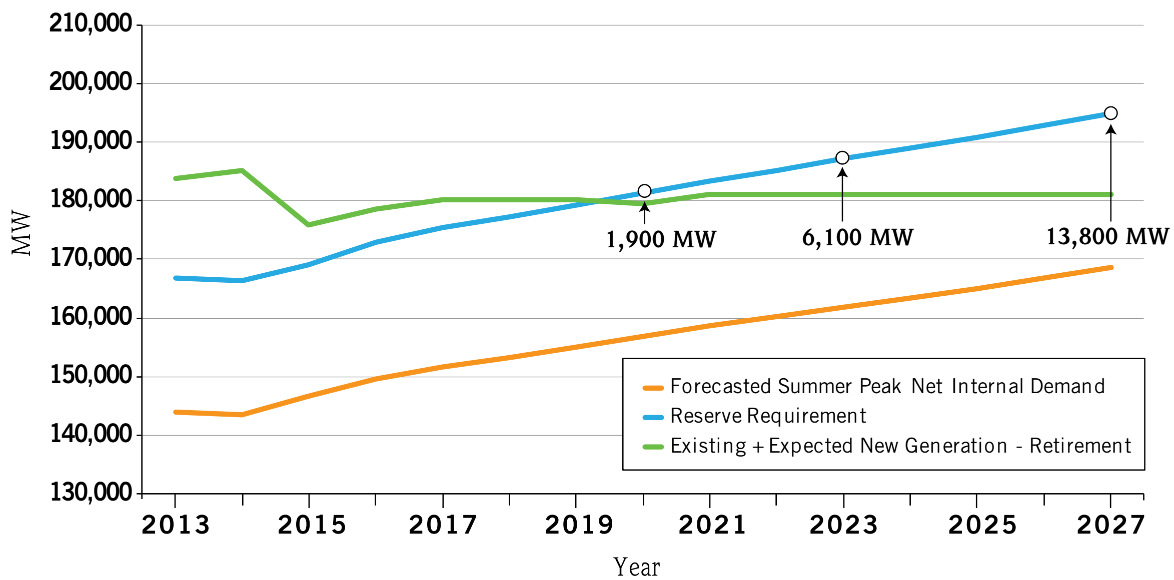


Table 7.2: Percent of Added Capacity by Region and Generator Type to Maintain PJM Reserve Margin

Region	Nuclear	Coal	Gas	Oil	Wind	Other Renewables	Total Region
AECO/DPL/JCPL/PECO/PSEG	0.8%	0.0%	21.6%	0.0%	0.4%	0.8%	23.6%
AEP/APS/COM/DAY/DUQ/ATSI/DEOK/EKPC	1.1%	4.6%	30.2%	0.1%	5.3%	1.5%	42.7%
BGE/PEP	0.0%	0.0%	8.6%	0.0%	0.0%	0.4%	9.0%
DOM	0.0%	0.0%	6.7%	0.0%	0.3%	0.2%	7.3%
ME/PN/PPL	0.1%	0.0%	16.7%	0.0%	0.5%	0.1%	17.4%
Total for PJM	2.0%	4.6%	83.8%	0.1%	6.5%	3.0%	100.0%

*** NOTE**

Beginning with PJM's 2014 RTEP cycle of Market Efficiency Studies, all generators which have executed a Facilities Study Agreement and/or an Interconnection Service Agreement will be added to simulation models. To the extent necessary, existing and queued generating units will be scaled based on location and technology to meet PJM load and reserve requirements. Transmission upgrades required to address congestion arising from the scaling assumptions will also be modeled.

Fuel Price Assumptions

PJM uses a commercially available database tool which includes fuel price forecasts for each fuel type. Forecasts for short-term gas and oil prices are derived from NYMEX future prices. Long-term forecasts are obtained from commercially available databases, as are coal price forecasts.

In addition, vendor provided basis adders are applied to account for commodity transportation cost to each PJM zone. The fuel price forecasts to be used in PJM's 2013 Market Efficiency Analyses are represented in **Figure 7.3**.

Load and Energy Forecasts

PJM's January 2013 Load Forecast Report provided the transmission zone load and energy data to be modeled in the market efficiency simulations. Energy efficiency that cleared in the May 2012 RPM Auction will be incorporated into the load model. See **Table 7.3** for a representation of PJM peak load and energy values to be used in the 2013 Market Efficiency Analysis.

Demand Resources

The amount of demand resource to be modeled in each transmission zone is based on the January 2013 PJM Load Forecast Report. The total PJM quantity modeled is shown in **Table 7.4**. Within the market efficiency models the transmission zone breakdown is consistent with the PJM Load Forecast Report.

Figure 7.3: Fuel Price Assumptions – 2013 Market Efficiency Analysis

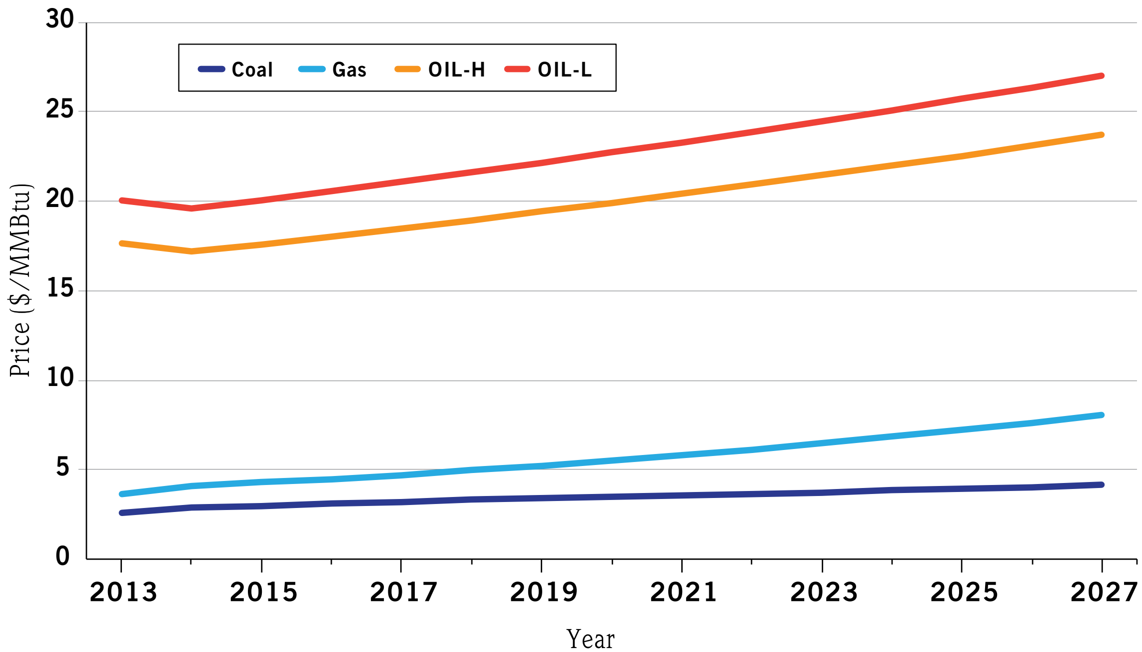


Table 7.3: PJM Peak Load and Energy Forecast

Load	2013	2014	2017	2018	2020	2023	2027
Peak (MW)	154,712	157,793	166,320	167,922	171,477	176,548	183,188
Energy (GWh)	819,195	835,603	884,564	894,019	915,237	942,569	978,583

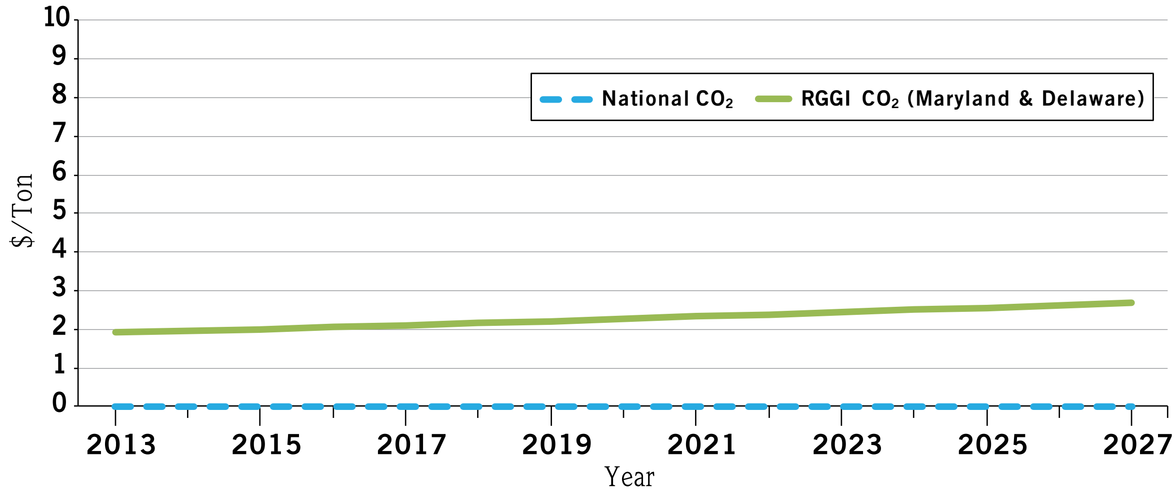
Table 7.4: Forecast PJM Demand Resources

	2013	2014	2017	2018	2020	2023	2027
Demand Resource (MW)	10,742	14,220	14,648	14,648	14,648	14,648	14,648

Emission Allowance Price Assumptions

PJM currently models three major effluents – SO_2, NO_x, and CO_2. SO_2 and NO_x emission price forecasts will reflect the Clean Air Interstate Rule (CAIR) as the Cross State Air Pollution Rule (CSAPR) was vacated in 2012. Because the CAIR rules impart a less stringent emissions requirement, and environmental retrofits and unit retirements should enable emissions compliance targets to be more easily met, the incremental cost of SO_2 and NO_x will be set to zero for market efficiency purposes. PJM unit CO_2 emissions will be modeled as either part of the national CO_2 program or, for Maryland and Delaware units, as part of the Regional Greenhouse Gas Initiative (RGGI) program. The emission prices for the national CO2 program will be set to zero for all study years to reflect stalled federal legislation regarding greenhouse gases. While the RGGI program CO_2 emissions price will be set to a non-zero value for all study years. See **Figure 7.4** for CO_2 emission allowance price assumptions.

Figure 7.4: CO_2 Emission Price Assumptions – 2013 Market Efficiency Analysis



Carrying Charge Rate and Discount Rate

In order to determine and evaluate the potential economic benefit of RTEP projects specifically targeted for economic efficiency, PJM will perform market simulations and calculate a benefit-to-cost ratio for candidate proposals. Doing so requires that the net present value of annual benefits are calculated for the first 15 years of upgrade life and compared to the net present value of the upgrade revenue requirement for the same 15-year period.

A discount rate and levelized carrying charge rate are developed using information contained in Transmission Owner formula rate sheets (Attachment H) as posted on PJM's website: http://www.pjm.com/markets-and-operations/transmission-service/formula-rates.aspx.

The discount rate itself is based on weighted average after-tax embedded cost of capital (average weighted by TO total capitalization). The levelized annual carrying charge rate is based on weighted average net plant carrying charge (average weighted by TO total capitalization) levelized over an assumed 45-year life of the project. PJM's 2013 market efficiency studies will use a levelized annual carrying charge rate of 16.7 percent and a discount rate of 7.7 percent.

Section 8 – 2013 Scenario Studies

8.1: Scenario Studies Overview

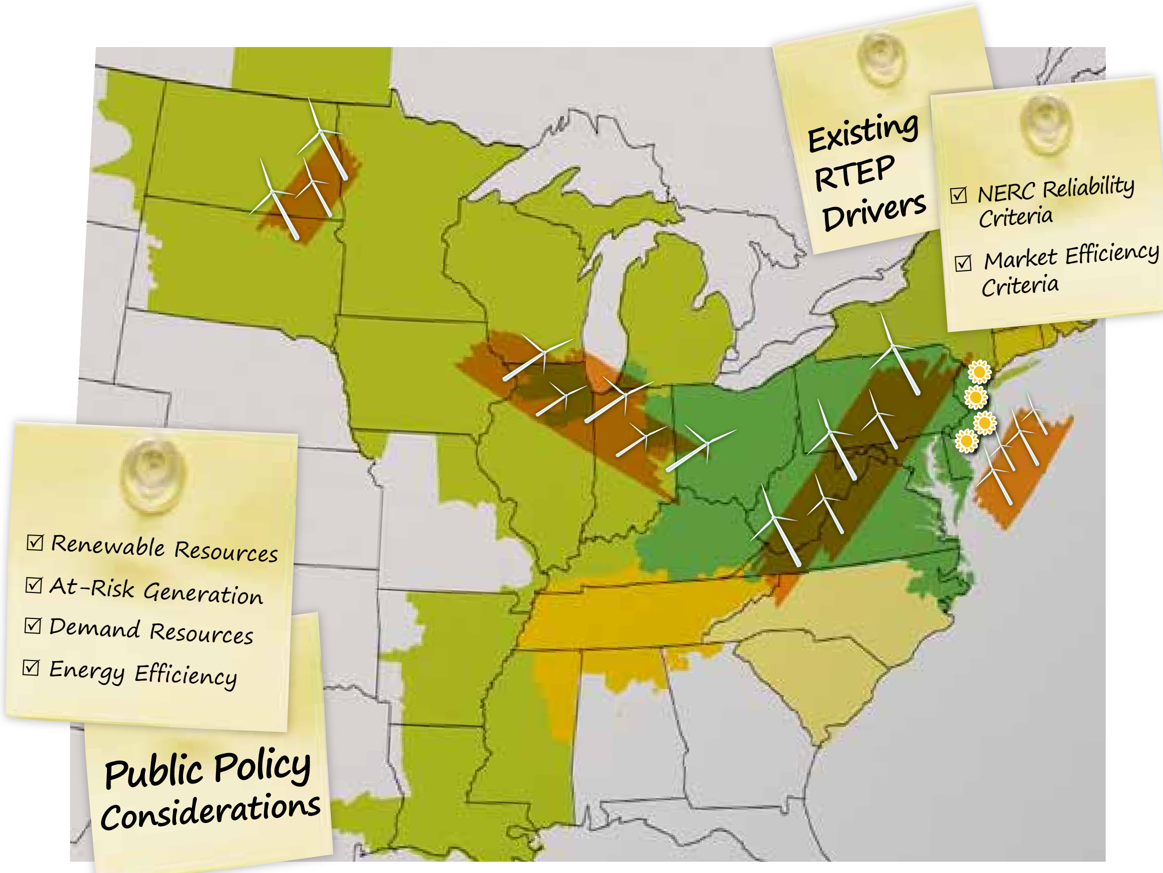
PJM's RTEP process considers the aggregate effects of many system trends: long-term growth in electricity use, generating plant retirements, broader generation development patterns – including greater penetration of renewable resources – as well as the impacts of demand resource and energy efficiency programs, depicted in **Figure 8.1**.

Over the past several years, an increasing focus by federal and state governments on environmental and other policy areas continues to make clear the critical role of the PJM transmission system.

And, while the existence of violations of NERC Reliability Standards has been the basis for PJM's determination of need, construction of major transmission infrastructure will likely be necessary to support the achievement of public policy goals: state Renewable Portfolio Standard (RPS) requirements, for example.

These policies as well as demand resource and energy efficiency programs, and the environmental compliance that continue to impact PJM's coal-fired generating fleet, whether taken individually, or addressing their collective impact, have begun to drive transmission planning decisions.

Figure 8.1: Public Policy Drivers



PJM's RTEP Process

The landscape in which PJM conducts planning has changed. PJM is in the process of implementing proposed expansions to its RTEP protocol, consistent with the term of its October 25, 2012 FERC Order No. 1000 compliance filing:

1. Expanded scenario planning and communications elements,

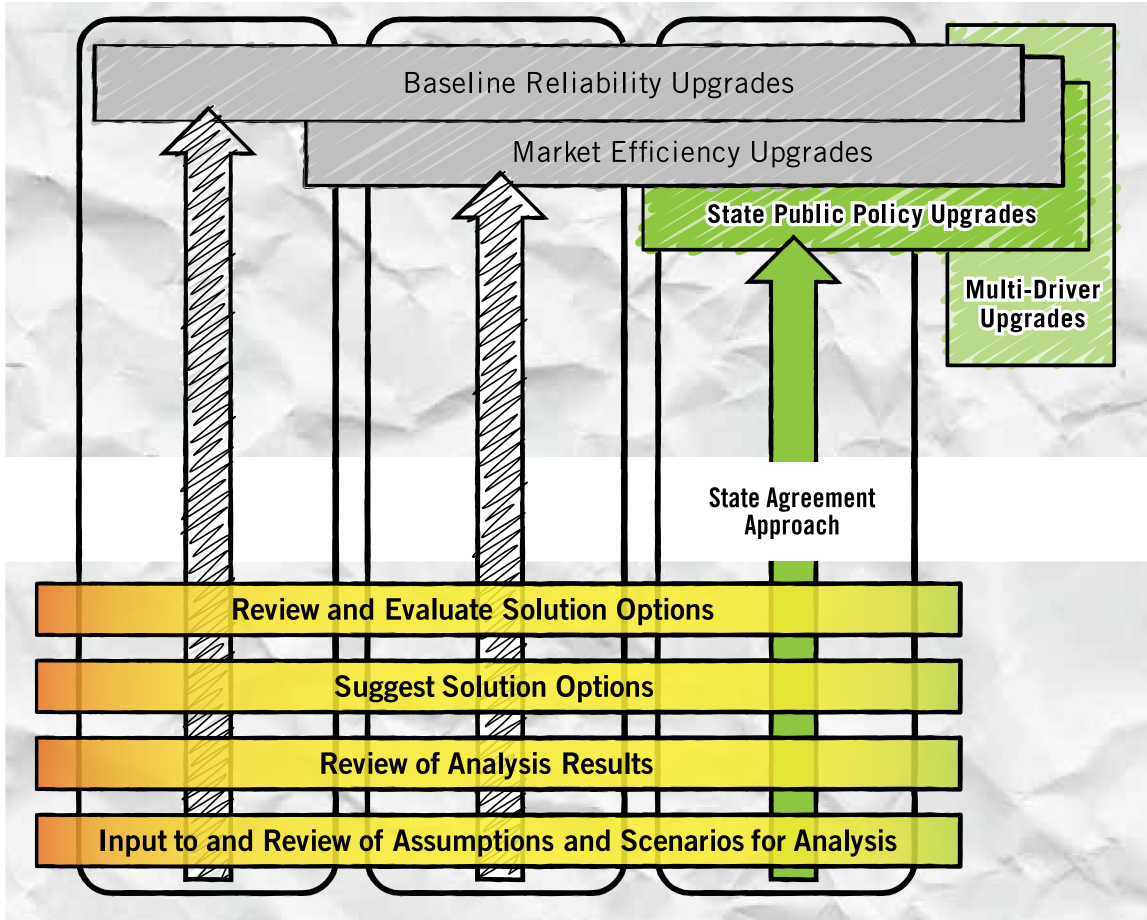
2. Expanded RTEP decision-making framework that includes a State Agreement Approach to consider state-based public policy upgrades, including those that may be a component of multi-driver expansion plans.

Shown in **Figure 8.2**, these new elements rely on a foundation of analysis and stakeholder interaction. While reliability and market efficiency requirements will continue to be a fundamental part of the RTEP protocol, decision-making must be expanded to address new and emerging factors as well as additional variability in factors that have traditionally driven need for system expansion.

The Growing Need for Scenario Analysis

Since its inception in 1997 and until recently, PJM generally found that the magnitude of uncertainty regarding future system conditions was limited. RTEP process tests could reasonably define the expected date of future reliability violations. This allowed PJM to plan new transmission facilities with minimal risk of fluctuating dates marking the expected onset of those violations. That has changed in many respects.

Figure 8.2: RTEP Process Decision Making



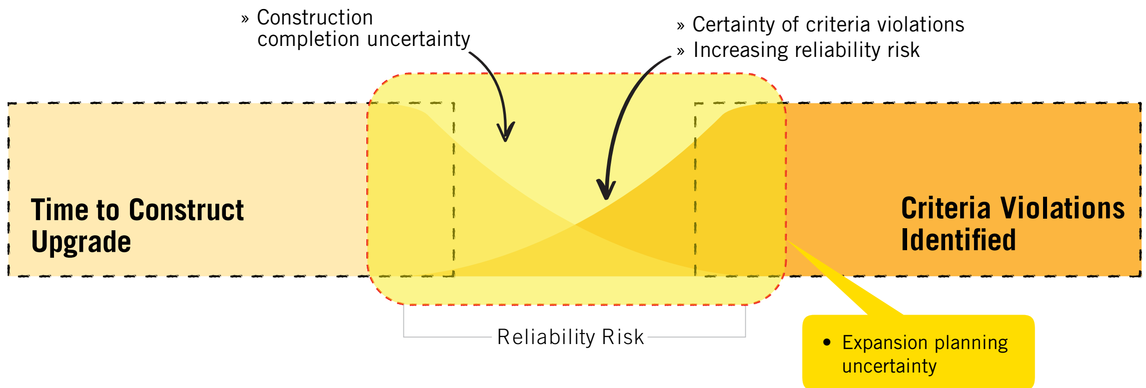
Onset of Criteria Violations

Uncertainty around the onset of reliability criteria violations is not characterized by a definitive step function. Violations may occur earlier or later than expected as shown in **Figure 8.3**. This arises from the volatility of input parameters that shift violations in time. A single set of baseline and market assumptions are simply not sufficiently flexible to consider all these emerging factors.

Backbone transmission projects cannot be effectively planned, funded, approved and constructed if they are continually taken on and off the table – the whip-saw effect – based on updated planning assumptions. Once a project is shelved, it cannot simply be put back on track when changing system conditions, revised load forecasts (for example) and other factors, which may have supported project delays a few months earlier, suddenly turn in the other direction.

The complexity does not end there. Regional expansion planning drivers can cut both ways. Any one individual factor may contribute to the need for one transmission expansion upgrade and simultaneously mitigate the need for another. This is particularly true with the impacts of clustered generation additions. Location is everything. New generation at one interconnection point may increase cross-system power transfers while another may back them off thereby helping to mitigate congestion.

Figure 8.3: Transmission Expansion Uncertainty and Risk



2013 RTEP Process Scenario Studies

Over the past several years an increasing focus of federal and state governments on environmental and other policy areas continues to make clear the critical role that transmission plays in making these policies a reality. And, while the existence of violations of NERC Reliability Standards has been the basis for PJM's determination of need, construction of major transmission infrastructure will likely be necessary to support the achievement of public policy goals. To that end, PJM's 2013 RTEP Process includes at-risk generation, Renewable Portfolio Standards (RPS) and Demand Resource Buy-back scenario analyses.

8.2: At-Risk Generation Scenario Study

Driven by economics, unit owners are assessing the increasing costs associated with unit age – some more than 40-years old – and changing environmental public policy, particularly with regard to air emission regulations. PJM has closely monitored proposed and finalized environmental rules issued at the Federal and State levels affecting electric generating units – coal-fired units in particular – to examine their impact on transmission reliability and resource adequacy.

Market Activity Impacts Revenue Streams

Ultimately, the need to comply with evolving federal and state environmental restrictions can affect a coal-fired generator's ability to recover sufficient revenue to remain economically viable. PJM's capacity market is often a main source of a generating unit's revenue stream. Thus, a unit's ability to clear an RPM auction may be an indicator of the plant's future viability, particularly if compared to competitors more efficient plants.

Costs related to a range of factors drive the ability of a plant to derive consistent revenue streams from PJM's energy, capacity and ancillary service markets. From a market participation perspective, a generator must weigh the additional revenue stream that an RPM auction-cleared generating resource could provide against the risk that the same generator may not clear an auction. A higher auction bid may be required to factor in higher capital costs or operating and maintenance costs, the result of tighter environmental regulations. Such at-risk units also face capacity market competition from more efficient power plants as well as demand resource and energy efficiency programs, for example.

From an energy market perspective, the cost of natural gas has put additional economic pressure on coal-fired generation. Fewer coal-fired units are being dispatched in favor of gas-fired units in PJM's real-time energy market during actual system operation. Consequently, ability of coal-fired plants to derive sustainable revenue streams is further diminished.

Ultimately, the decision to retrofit or retire an at-risk unit will be made by the individual generation owner based on its own cost recovery requirements (e.g. term and internal rate of return), expectations regarding future economic conditions (e.g., natural gas prices, fuel mix of competing capacity and consumer electricity demand) and the shape of future environmental policy affecting the industry.

System Impacts

Scenario studies performed in 2011 and 2012 framed the reliability issues PJM and stakeholders could face over the next 15 years from unit deactivations. Generator deactivations alter power flows that often yield transmission line overloads and, given reductions in system reactive support from those generators, can undermine voltage support.

Readers are encouraged to review PJM's 2012 RTEP Report, Book 4, Section 2 which discusses details of 2012 at-risk generation scenario study scope and results. That report is accessible from PJM's website via the following URL: http://www.pjm.com/~/media/documents/reports/2012-rtep/2012-rtep-book-4.ashx.

At-risk generation scenario studies in 2013 will advance PJM understanding of system impacts further.

2018 Study Year

PJM will also conduct a five-year-out power flow analysis on a 2018 study year case to assess the reliability impacts from the deactivation of units that remain on PJM's At-Risk list; this comprises less than 5,000 MW of generation. This is in addition to the known generation with formal notification of intended deactivation by June 1, 2018 which will be modeled offline. All RTEP upgrades to solve reliability criteria violations caused by those generators will also be modeled.

The majority of the units previously on PJM's At-risk generation list were older coal units, which may have violated potential new EPA regulations. In the past year and half a large number of those generators have announced their intention to deactivate, and have been studied through PJM's deactivation process.

A generator is considered at-risk if it has not announced its intention to deactivate, has no plans to install environmental controls, and has been deemed at-risk by PJM using econometric data including RPM auction results. Generators who have announced their deactivation or have plans to install environmental controls are not considered at-risk. This process is consistent with the methodology described in PJM's 2012 RTEP report, Book 4, Section 2, per the website URL cited earlier.

Scenario studies of this nature have typically included the following tests on monitored facilities at 230 kV and above, as conducted in 2012:

- Baseline contingency analysis - thermal and voltage
- Generator Deliverability (50/50 load level) – Thermal
- Common Mode Outage (50/50 load level) – Thermal
- Load Deliverability (90/10 load level)
    - MAAC – Thermal and Voltage
    - EMAAC – Thermal and Voltage
- N-1-1 (50/50 load level – Thermal and Voltage

Following completion of these analyses, PJM will also conduct a sensitivity study to examine the additional reliability impact of modeling queued generation projects that have executed a Facilities Study Agreement.

8.3: Renewable Portfolio Standard (RPS) Scenario Study

Legislative and regulatory Renewable Portfolio Standards (RPS) public policy initiatives by the federal government and many state governments continue to drive RTO-wide impacts, bringing into clear focus the critical role of the PJM transmission system in delivering power reliably from a changing generation landscape. Specifically, State RPS require entities that serve load do so using various eligible resource types including wind, solar and other technologies. States in the PJM region have a variety of RPS definitions and targets as identified on **Map 8.1** and in **Table 8.1**.

Federal RPS Public Policy

The development of wind generation is a significant component of U.S. federal energy policy as well. In recent years the federal government has encouraged the development of wind generation facilities with legislation that provides tax incentives and Production Tax Credits (PTCs) for wind-powered facilities. The American Recovery and Reinvestment Act (ARRA) enacted in February 2009 provided a three-year extension of the PTC through December 31, 2012. In January, 2013, federal legislation passed as part of fiscal cliff deadline action extended production tax credits through 2013 and now includes all wind-powered projects that start construction in 2013, not just those completed in 2013.

The Need for RPS Scenario Studies

Wind-powered generating resources continue to play a growing role in meeting PJM customer load requirements since 1999. In the past several years, PJM has seen increased interest in wind-powered generating facilities off the Atlantic coast and in the Mid-West U.S. for import into PJM. As such, the transmission facilities necessary to deliver the output of all new generation reliably become all the more vital.

PJM conducted an RPS scenario study as part of its 2012 RTEP process to continue to enhance its understanding of RPS public policy impacts on transmission expansion plans. Building on 2010 and 2011 scenario studies, PJM's 2012 study refined input parameters based on broader PJM operational RPS study efforts and specific formal requests for specific sensitivity analyses by states. PJM's 2012 RTEP Report, Book 4, Section 3 which discusses details of 2012 RPS scenario study scope and results, accessible from PJM's web site via the following URL: http://www.pjm.com/~/media/documents/reports/2012-rtep/2012-rtep-book-4.ashx.

2013 Analysis

Each successive annual RPS Scenario study provides PJM and stakeholders with additional insights on the reliability and economic impacts of renewable-driven generation resource potential end-states. PJM's 2013 RTEP process will continue this exploration. System models will be updated with the latest load forecast data, generation additions and deactivations and approved RTEP upgrades. Proposed off-shore HVDC modeling will be updated as well. Generation modeling will be refined with additional detail on generation minimum output levels and other unit characteristics. Specifically, the scope of 2013 market efficiency scenario study analyses will focus on economic impacts in terms of wind curtailment, congestion, load payments and LMP changes.

The 2012 RPS Scenario Study evaluated generation resource expansion scenarios developed to meet 2027 state RPS objectives. As part of 2013 efforts, PJM will update the three generation expansion scenarios to meet 2028 state RPS objectives. Results will be reported on a state-by-state basis. PJM will also continue to study the proposed transmission overlay developed to address the issues identified in 2012 analyses. That portion of 2013 study efforts will focus on evaluating and tailoring the proposed transmission overlay to determine which portions may or may not now be required in light of the three scenarios studied.

Following completion of those analyses PJM also plans to conduct a sensitivity study to examine unit commitment assumptions used in production cost simulations and their potential impacts on wind curtailment.

Map 8.1: State Renewable Portfolio Standard Requirements

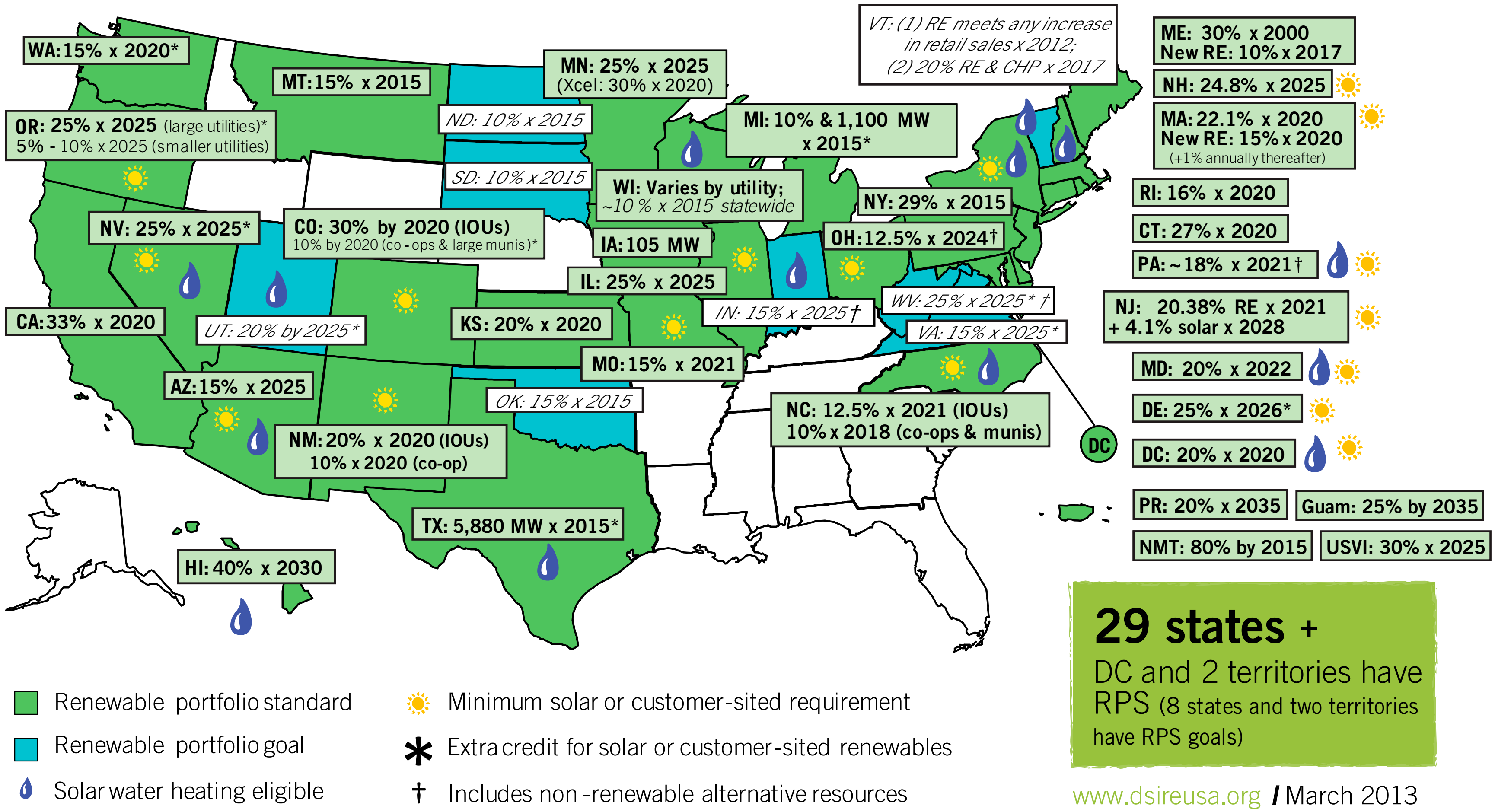


Table 8.1: Renewable Portfolio Standards Initiatives in PJM States

Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States						
	Regulation or Legislation	Geographic Eligibility	Alternative Compliance Payment (ACP)	Credit Multipliers	RPS Year	Percentage
DC	Bill 15-747 (2005) Bill 17-0492 (2008) Bill 18-0223 (2010) Bill 19-10 (2011)	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. (3) Solar resource must be located in within D.C.	Tier 1 - $50/MWh Tier 2 - $10/MWh Solar - $500/MWh in 2009 thru 2016, $350 in 2017, declining to $50 in 2023 and thereafter.	N/A	2020	Total – 20%
DE	Senate Bill 74 (2005) Senate Bill 19 (2007) Senate Bill 328 (2008) Senate Bill 119 (2010) Senate Bill 124 (2011)	"Eligible Energy Resources" include energy resources located within or imported into the PJM region.	$25/MWh for 1st deficient year. $50/MWh for 2nd deficient year. $80/MWh for 3rd+ deficient year. Solar ACP: $400/MWh for 1st deficient year, $450/MWh for 2nd deficient year, $500/MWh for 3rd+ deficient year	a). 300% credit for (1) in-state solar electric or (2) renewable fuel cells installed on or before 12/31/2014. b). 150% credit for wind energy installations sited in Delaware on or before 12/31/2012. c). 350% credit for wind energy installations sited off the DE coast on or before 5/31/2017. 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.	2025/26	Total – 25%
IL	Public Act 095-0481 H.B. 6202 (2010) H.B. 1458 (2011 S.B. 1652 (2011)	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.	N/A	N/A	2025/2026	25%
IN	S.B. 251 (2011)	At least 50% of qualified clean energy must come from within Indiana.	None. Voluntary goal.	N/A	2025	10%
MD	HB 1308 / SB 869 SB 595 (2007) HB 375 (2008) S.B. 277 (2010) S.B. 690 (2011) S.B. 717 (2011) S.B. 791 (2012)	Source Must be located in the PJM Region.	Tier 1 - $40 / MWh Tier 2 - $15 / MWh Solar - $450 / MWh in 2008 $400 / MWh in 2010, declining to $50 / MWh in 2023	N/A	2022	Total – 20%

Table 8.1: Renewable Portfolio Standards Initiatives in PJM States (Continued)

Comparison of Renewable Portfolio Standards (RPS) Programs in PJM States						
	Regulation or Legislation	Geographic Eligibility	Alternative Compliance Payment (ACP)	Credit Multipliers	RPS Year	RPS Percentage
MI	Public Act 295 (2008)	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.	Not applicable for the Renewable Energy Requirement.	a). Solar receives an additional 2 credits per MWh. b). Lesser bonuses awarded for on-peak production, storage, and using in-state labor or equipment.	2015	10%
NC	SB 3 (2007) SB 960 (2009) SB 886 (2010) SB 75 (2011)	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.	N/A	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.	2021	12.5%
NJ	N.J.A.C 14:4-8 - (2004) AB 3520 (2010) SB 2036 (2010) SB 1925 (2012)	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.	Class I & II (ACP) - $50/MWh Solar (SACP) – $641/MWh in 2012/13, dropping to $339 in 2013/14, then declining to $239 by 2027/28.	N/A	2020/2021	Total – 23.85% Solar: 3.47% in 2020/21 4.10% in 2027/28
OH	SB 221 (2008) SB 315 (2012)	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.	REC - $45.93/MWh Solar – $400/MWh 2010 and 2011, reduced by $50 every two years thereafter.	N/A	2024	12.5%
PA	Senate Bill 1030 Act 213, HB 1203 (2007) Act 35	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.	Tier I & Tier II - $45 / MWh Solar – 200% of the average market value for solar RECs sold in the RTO.	N/A	2020/2021	Tier I – 8.0% Total – 18.0%
VA	SB 1416 (2007) SB 718 (3/2008) HB 1022 (2010) HB 232 and HB 1102 (2012)	Electricity must be generated or purchased in Virginia or in the interconnection region of the regional transmission entity.	None. Voluntary goal.	a). Onshore wind and solar power receive a double credit toward RPS goals. b). Offshore wind receives triple credit toward RPS goals. c) Research and development expenses related to renewable energy can meet up to 20% of the RPS goal	2022	12%
WV	H.B. 408 (2009) S.B. 350 (2010)	Electricity produced must be generated or purchased from a facility in West Virginia or in the PJM Service Territory	The Less of: a). $50/MWh b). 200% of REC average market value for given compliance year.	a). One credit per MWh from alternative energy resource facilities. b). Two credits per MWh from renewable energy resource facilities. c). Three credits are received for each MWh of electricity generated from a renewable energy resource located on a reclaimed surface mine in West Virginia.	2025	25%

Hudson – Cardiff Sensitivity Study*

At the request of the state of New Jersey, PJM 2013 scenario analysis will also include a sensitivity study to evaluate a Hudson – Cardiff offshore HVDC transmission line as a potential solution to offshore renewable energy needs. The sensitivity study will examine the capability of the HVDC line to accommodate offshore 1,000 MW wind-powered energy injections at both the Hudson and Cardiff Substations and its effectiveness in relieving potential constraints to satisfy state RPS objectives. No other off-shore wind will be modeled and no changes to on-shore wind project modeling will be made. Results will be conveyed to New Jersey officials and PJM stakeholders accordingly.

*** NOTE**

PJM completed the Hudson – Cardiff Sensitivity Study in early 2013. Results were reported to PJM stakeholders at the TEAC meeting of February 7, the presentation materials for which are accessible from PJM's web site via the following URL link: http://www.pjm.com/~/media/committees-groups/committees/teac/20130207/20130207-reliability-analysis-update.ashx.

8.4: Demand Resource Buy-Back Scenario Analysis

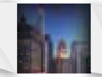
As part of load forecast development, PJM uses the results of its forward capacity auctions to adjust the base, unrestricted load forecast to account for Demand Resources and Energy Efficiency. This peak load forecast is then used in the development of RTEP power flow models. Thus the status and availability of demand resources can have a measurable impact on the assessment of future system conditions that drive the need for new transmission to meet load-serving responsibilities.

The past several years have witnessed the emergence of demand resource programs across PJM under the aegis of various state initiatives. Sound planning practices, though, require PJM to ensure reliability such that the effects of load management are only considered once they have cleared Reliability Pricing Model (RPM) three-year-forward capacity market and demonstration of all attendant related and operational obligations.

Assessing Impacts of Demand Resource Buy-Back

Over several recent incremental RPM auctions, however, PJM has begun to see transactions in which owners of existing generation that has not cleared a Base Residual Auction and has not pursued deactivation, are buying out the positions of providers of Demand Resources that have cleared a prior auction. In light of this, PJM has begun efforts to identify potential locational supply concerns.

PJM RTEP power flow base cases model the impact of both existing generation that has not cleared (and has not deactivated) and demand resources that have cleared. Given that those demand resources may now not be realized, PJM is conducting a scenario study in 2013 that examines this impact. As currently scoped, the study will include load deliverability analysis for which power flow cases will be developed that model, on an LDA basis, a reduction in the level of demand resources by the amount of generation that did not clear an RPM Auction. Reliability criteria violations and other results will be reviewed and discussed with stakeholders in TEAC meeting forums.

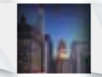


Appendix 1 - 2013 Machine List

Appendix 1 comprises the machine list of all generating units modeled in PJM's 2013 RTEP process cycle 2018 study year power flow base case as discussed in **Section 4.2**. The entire machine list has been posted to PJM's website and is accessible via the following URL link: http://pjm.com/~/media/documents/reports/rtep-plan-documents/2013-input-assumptions-white-paper-appendix-1.ashx.

Please note that this machine list may change, for example, to reflect the outcome of the most recent May, 2013 RPM Base Residual Auction.

Please also note that announced generator deactivations are not included in the machine list either.



Appendix 2 - ISA and FSA Generation

Appendix 2 comprises the list of generating units modeled in PJM's 2013 RTEP process cycle 2018 study year power flow base case that have executed a Facilities Study Agreement (FSA) or an Interconnection Service Agreement (ISA), as discussed in **Section 4.2**.

The entire list has been posted to PJM's website and is accessible via the following URL link: http://pjm.com/~/media/documents/reports/rtep-plan-documents/2013-input-assumptions-white-paper-appendix-2.ashx.

Appendix 3 - PJM Load Deliverability Areas

Map A1: PJM Load Deliverability Areas

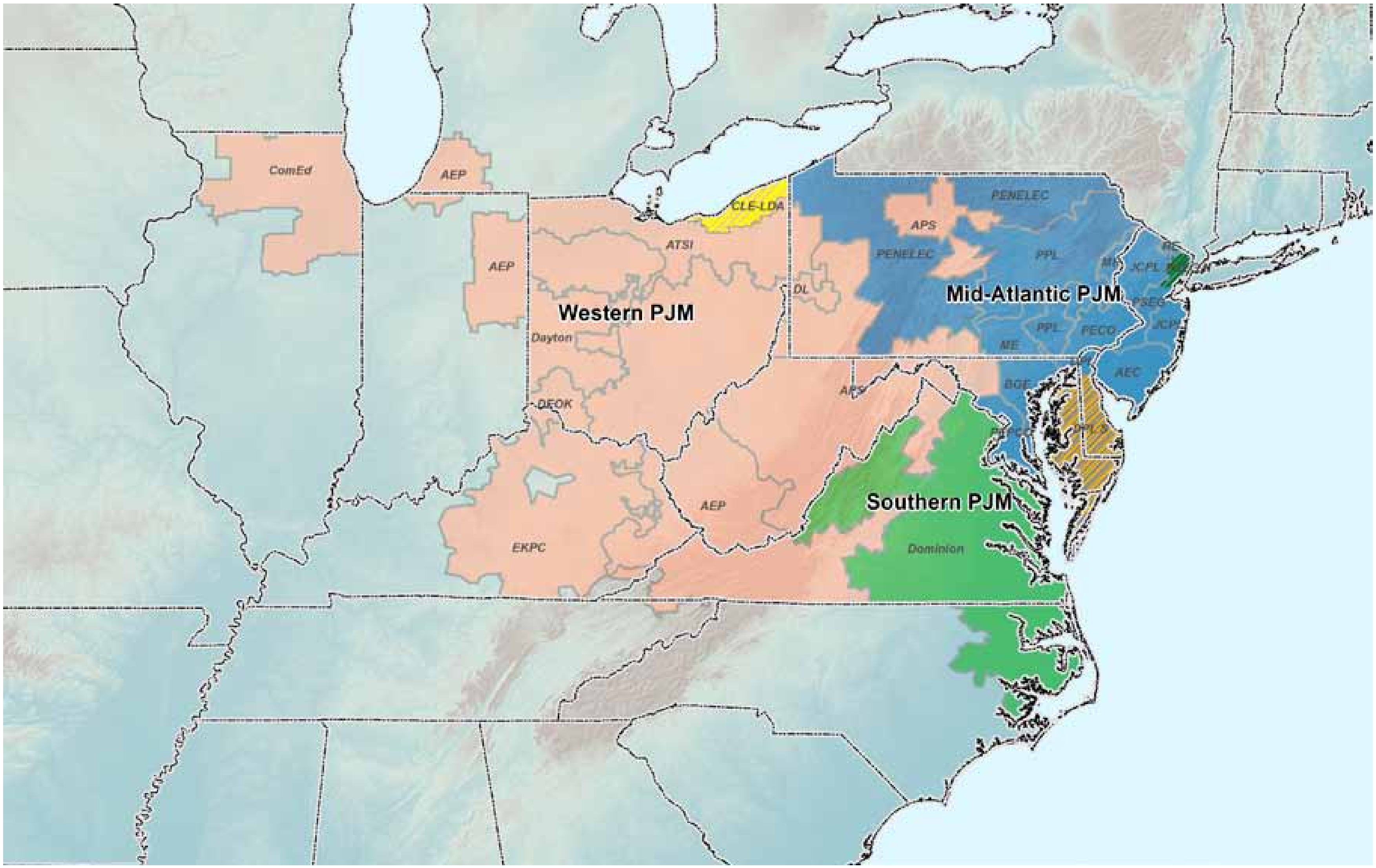
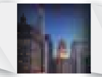


Table A1: PJM LDA Descriptions

LDA	Description
EMAAC	Global area - PJM 500, JCPL, PECO, PSEG, AE, DPL, RECO
SWMAAC	Global area - BGE and PEPCO
MAAC	Global area - PJM 500, Penelec, Meted, JCPL, PPL, PECO, PSEG, BGE, Pepco, AE, DPL, UGI, RECO
PPL	PPL & UGI
PJM West	APS, AEP, Dayton, DUQ, Comed, ATSI, DEO&K
WMAAC	PJM 500, Penelec, Meted, PPL, UGI
PENELEC	Pennsylvania Electric
METED	Metropolitan Edison
JCPL	Jersey Central Power and Light
PECO	PECO
PSEG	Public Service Electric and Gas
BGE	Baltimore Gas and Electric
PEPCO	Potomac Electric Power Company
AE	Atlantic City Electric
DPL	Delmarva Power and Light
DPLSOUTH	Southern Portion of DPL
PSNORTG	Northern Portion of PSEG
VAP	Dominion Virginia Power
APS	Allegheny Power
AEP	American Electric Power
DAYTON	Dayton Power and Light
DLCO	Duquesne Light Company
Comed	Commonwealth Edison
ATSI	American Transmission Systems, Incorporated
DEO&K	Duke Energy Ohio and Kentucky
EKPC	East Kentucky Power Cooperative
Cleveland	Cleveland Area



Glossary

The terms and concepts in this glossary are provided for the convenience of the reader and are in large part based on definitions from other sources, as indicated in the "Reference" column for each term. These references include the following:

M-xx – PJM Manual - http://www.pjm.com/documents/manuals.aspx

NERC – North American Electric Reliability Council - http://www.nerc.com/

OA – PJM Operating Agreement - http://www.pjm.com/documents/agreements/pjm-agreements.aspx

OATT – PJM Open Access Transmission Tariff - http://www.pjm.com/documents/agreements/pjm-agreements.aspx

RAA – Reliability Assurance Agreement - http://www.pjm.com/documents/agreements/pjm-agreements.aspx

Term	Reference	Acronym	Definition
Adequacy	NERC		Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. "Resources" refers to a combination of electricity generating and transmission facilities, which produce and deliver electricity, and "demand-response" programs, which reduce customer demand for electricity. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.
Ancillary Service	OATT		Those services necessary to support the transmission of capacity and energy from resources to loads while, in accordance with good utility practice, maintaining reliable operation of the transmission provider's transmission system.
Attachment Facilities	OATT		The facilities necessary to physically connect a Customer Facility to the Transmission System or interconnected distribution facilities.
Auction Revenue Right	OA	ARR	A financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the Annual FTR Auction.
Available Transfer Capability	NERC	ATC	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.
Baseline Upgrades	M-14B		In developing the RTEP, PJM tests the baseline adequacy of the transmission system to deliver energy and capacity resources to each load in the PJM region. The system as planned to accommodate forecast demand, committed resources, and commitments for firm transmission service for a specified time frame is tested for compliance with NERC and the applicable regional reliability council (Reliability*First* or SERC) standards, Nuclear Plant Licensee requirements, PJM Reliability Standards and PJM design standards. Areas not in compliance with the standards are identified and enhancement plans to achieve compliance are developed. The baseline analysis and the upgrade expansion plans that result are Baseline Upgrades and serve as the base system for conducting Feasibility Studies and System Impact studies for all proposed requests for generation and merchant transmission interconnection and for long-term firm transmission service. (Baseline upgrades are a subset of network upgrades.)

Term	Reference	Acronym	Definition
Behind The Meter Generation	OATT	BTM	Behind The Meter Generation refers to a generation unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities has consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of PJM); provided, however, that Behind The Meter Generation does not include (i) at any time, any portion of such generating unit's capacity that is designated as a Capacity Resource, or (ii) in an hour, any portion of the output of such generating unit[s] that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market.
Bilateral Transaction	OA		A contractual arrangement between two entities (one or both being PJM Members) for the sale and delivery of a service.
Bulk Electric System	NERC M-14B	BES	Reliability*First* defines the BES as all: Individual generation resources larger than 20 MVA or a generation plant with aggregate capacity greater than 75 MVA that is connected via a step-up transformer(s) to facilities operated at voltages of 100 kV or higher, Lines operated at voltages of 100 kV or higher, Associated auxiliary and protection and control system equipment that could automatically trip a BES facility, independent of the protection and control equipment's voltage level (assuming correct operation of the equipment). The Reliability*First* Bulk Electric System excludes: Radial facilities connected to load serving facilities or individual generation resources smaller than 20 MVA or a generation plant with aggregate capacity less than 75 MVA where the failure of the radial facilities will not adversely affect the reliable steady-state operation of other facilities operated at voltages of 100 kV or higher; The balance of generating plant control and operation functions (other than protection systems that directly control the unit itself and step-up transformer); these facilities would include relays and systems that automatically trip a unit for boiler, turbine, environmental, and/or other plant restrictions; All other facilities operated at voltages below 100 kV.
Capacity Emergency	M-13		System condition where operating capacity plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet the total of its demand, firm sales and regulating requirements.
Capacity Emergency Transfer Limit	RAA M-14B M-18	CETL	Part of Load Deliverability analysis to determine the maximum limit, expressed in megawatts, of a study area's import capability, under the conditions specified in the load deliverability criteria.
Capacity Emergency Transfer Objective	RAA M-14B M-18 M-20	CETO	The CETO is the emergency import capability, expressed in megawatts, required of a PJM sub-area to satisfy established reliability criteria.
Capacity Interconnection Rights	OATT	CIRs	The rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.
Capacity Resource	RAA M-14A M-14B		Megawatts of net capacity from existing or planned generation capacity resources or load reduction capability provided by Demand Resources or ILR in the PJM Region.
Combined Cycle		CC	A generating unit facility generally consisting of a gas-fired turbine and a heat recovery steam generator. Electricity is produced by a gas turbine whose exhaust is recovered to heat water, yielding steam for a steam turbine that produces still more electricity.
Combustion Turbine		CT	A generating unit in which a combustion turbine engine is the prime mover.
Construction Service Agreement		CSA	The terms and conditions of a CSA govern the construction of all transmission facilities for interconnection to the PJM transmission system. PJM and the developer execute a separate CSA with each impacted transmission owner. A developer retains the right ("Option to Build"), but not the obligation to design, procure, construct and install all or any portion of required transmission upgrades which are otherwise the obligation of the Transmission Owner to construct.
Contingency			The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Cost of New Entry	M-18	CONE	A RPM capacity market parameter defined as the levelized annual cost in ICAP $/MW-Day of a reference combustion turbine to be built in a specific LDA.

Term	Reference	Acronym	Definition
Deactivation			The retirement or mothballing of a generating unit governed by the PJM Open Access Transmission Tariff.
Deliverability	RAA M-14B		Deliverability is a test of the physical capability of the transmission network for transfer capability to deliver energy from generation facilities to wherever it is needed to ensure, only, that the transmission system is adequate for delivery of energy to load under prescribed conditions. The testing procedure includes two components: (1) Generation Deliverability; and (2) Load Deliverability.
Demand Resource	M-18	DR	See "Load Management"
Diversity	M-18		The amount of MWs that account for the difference between a Transmission Owner zone's forecasted peak load at the time of its own peak and its coincident load at the time of the PJM peak.
Distribution Factor		DFAX	The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)
Eastern Interconnection Planning Collaborative		EIPC	The EIPC represents a first-of-its-kind effort to involve planning authorities in the Eastern Interconnection to model the impact on the grid of various policy options determined to be of interest by state, provincial and federal policy makers and other stakeholders.
Eastern Kentucky Power Cooperative	M-14B	EKPC	EKPC is a Transmission Owner area located in the eastern portion of Kentucky. (EKPC officially integrated into PJM's on June 1, 2013.)
Eastern MAAC	M-14B	EMAAC	A term used in PJM deliverability analysis to refer to the portion of PJM that includes AE, DPL, JCPL, PECO, PSEG and Rockland.
Eastern Wind Integration and Transmission Study		EWITS	The EWITS was a regional wind integration study initiated in 2008 to examine the operational impact of up to 20-30 percent energy penetration of wind on the power system in the Eastern Interconnection of the United States. The study was set up to answer questions that utilities, regional transmission operators, and planning organizations had about wind energy and transmission development in the east.
Effective Forced Outage Rate on Demand	M-22	EFORd	A measure of the probability that generating unit will not be available due to a forced outages or forced deratings when there is a demand on the unit to generate. See Generator Resource Performance Indices Manual (M-22) for equation.
Electrical Distribution Company		EDC	A company that owns and/or operates electrical distribution facilities for the delivery of electrical energy to end-use customers.
Energy Efficiency Programs		EE	Incentives or requirements at the state or federal level that promote energy conservation and wise use of energy resources.
Energy Resource	M-14A M-14B	OATT	A generating facility that is not a capacity resource.
Extra High voltage		EHV	Transmission equipment operating at 230 kV and above
Fault			An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
Federal Energy Regulatory Commission		FERC	The Federal Energy Regulatory Commission, or FERC, is an independent agency that regulates the interstate transmission of electricity, natural gas and oil.
Financial Transmission Right	M-6	FTR	A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.
Firm Transmission Service	OATT		Transmission service that is intended to be available at all times to the maximum extent practicable. Service availability is subject to system emergency conditions, unanticipated facility failure or other unanticipated events, and is governed by Part II of the OATT.
Fixed Resource Requirement		FRR	Fixed Resource Requirement (FRR) is an alternative method for a Party to satisfy its obligation to provide Unforced Capacity. Allows a load serving entity to avoid direct participation in the RPM Auctions by meeting their fixed capacity resource requirement using internally owned capacity resources
Flowgate			A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.
Generation Deliverability	M-14B		The ability of the transmission system to export capacity resources from one electrical area to the remainder of PJM. The generator deliverability test for reliability analysis ensures that, consistent with the load deliverability single contingency testing procedure, the Transmission System is capable of delivering the aggregate system generating capacity at peak load with all firm transmission uses modeled.

Term	Reference	Acronym	Definition
Good Utility Practice	OATT		Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the region.
Independent System Operator		ISO	An entity that is authorized to operate an electric transmission system and is independent of any influence from the owner(s) of that electric transmission system. (See also "RTO")
Installed Capacity		ICAP	Valued based on the summer net dependable rating of the unit as determined in accordance with PJM, rules and procedures of the determination of generating capacity.
Interconnection Service Agreement	M-14A	ISA	An agreement among the Transmission Provider, an Interconnection Customer and an Interconnected Transmission Owner regarding interconnection under Part IV and Part VI of the Tariff.
Light Load Reliability Analysis	M-14B		Analysis to ensure that the transmission system is capable of delivering the system generating capacity during a light load situation (50 percent of 50/50 summer peak demand level).
Load			Demand for electricity at a given time, expressed in megawatts (MW).
Load Deliverability	M-14B		The ability of the transmission system to deliver energy from the aggregate of available capacity resources in one PJM electrical area and adjacent non-PJM areas to another PJM electrical area that is experiencing a capacity deficiency.
Load Management	M-18	LM	Retail customer load that can be interrupted at the request of PJM. Such a PJM request is considered an emergency action and is implemented prior to a voltage reduction. LM derives a Demand Resource or Interruptible-Load-for-Reliability credit in RPM.
Load Serving Entity	RAA OATT	LSE	Load-serving entities provide electricity to retail customers. LSEs include traditional distribution utilities.
Locational Deliverability Area	M-14B	LDA	Electrically cohesive load areas historically defined by transmission owner service territories and larger geographical zones comprised of a number of those service areas.
Locational Marginal Price		LMP	The hourly integrated market clearing marginal price for energy at the location the energy is delivered or received.
Loss-of-Load Expectation	M-14B	LOLE	Loss-of-load expectation (LOLE) defines the adequacy of capacity for the entire PJM footprint based on load exceeding available capacity, on average, during only one day in ten years (1/10).
Market Participant			A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met creditworthiness standards as established by PJM. Market buyers are otherwise able to make purchases and market sellers are otherwise able to make sales in PJM Energy and Capacity Markets.
Mid-Atlantic Sub Region	M-14B	MAAC	The PJM Mid-Atlantic Sub-Region encompasses 12 transmission owner zones: Atlantic City Electric Company (AE), Baltimore Gas and Electric (BGE), Delmarva Power and Light (DPL), Jersey Central Power and Light (JCPL), Metropolitan Edison Company (METED), Neptune, PECO Energy (PECO), Pennsylvania Electric Company (PENELEC), PEPCo Holdings (PEPCo), PPL Electric Utilities Corporation (PPL), Public Service Electric and Gas (PSEG), Rockland Electric (Rockland) and UGI Corporation (UGI). The Neptune Regional Transmission System interconnects with the Mid-Atlantic PJM transmission system at Sayreville substation in Northern New Jersey.
Merchant Transmission Facility	OATT		A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System in accordance with the PJM Open Access Transmission Tariff. These facilities are not existing facilities of the transmission system; transmission facilities included in the rate base of a public utility on which a regulated return is earned;included in previous RTEPs; or,customer interconnection facilities.
MVAR	OA		See "Reactive Power"
National Renewable Energy Laboratory		NREL	NREL, part of the Department of Energy, is a federal laboratory dedicated to the research, development, commercialization and deployment of renewable energy and energy efficiency technologies.

Term	Reference	Acronym	Definition
Network Upgrades	OATT		Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.
North American Electric Reliability Corporation	NERC	NERC	NERC is an international, independent, self-regulatory, not-for-profit organization, whose mission is to ensure the reliability of the bulk power system in North America.
Nuclear Plant Interface Requirement		NPIR	NREL, part of the Department of Energy, is a federal laboratory dedicated to the research, development, commercialization and deployment of renewable energy and energy efficiency technologies.
Open Access Same-Time Information System		OASIS	The Open Access Same-Time Information System (OASIS) provides information by electronic means about available transmission capability for point-to-point service and a process for requesting transmission service on a non-discriminatory basis. OASIS enables transmission providers and transmission customers to communicate requests and responses to buy and sell available transmission capacity offered under the PJM Open Access Transmission Tariff.
Open Access Transmission Tariff	OATT	OATT	A FERC filed tariff specifying the terms of conditions under which PJM provides transmission service and carries out its generation and merchant transmission interconnection process.
Optimal Power Flow		OPF	A tool used to determine the optimal dispatch, subject to transmission constraints. Optimal often means most economical, but may also mean minimum control change.
PJM Manuals			The instructions, rules, procedures and guidelines established by PJM for the operation, planning and accounting requirements of the PJM Region and the PJM Interchange Energy Market.
PJM Member	OA M-33		Any entity that has completed an application and satisfies the requirements of PJM to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.
Planning Committee	OA	PC	A committee established under the operating agreement to review and recommend system planning strategies and policies as well as planning and engineering designs for the PJM bulk power supply system.
Planning Cycle	M-14B		The annual RTEP Process series of studies, analysis, assessments and related supporting functions.
Planning Horizon	M-14B		The future time period over which system transmission expansion plans are developed based on forecasted conditions.
Probabilistic Risk Assessment	M-14B	PRA	PJM assesses risk exposure using a PRA risk management tool. Initially, this tool is used to assess the risk of PJM's aging 500/230 kV transformer fleet. The goal of the PRA model is to minimize asset service cost. PJM's PRA method integrates the economics of transformation loss with the likelihood of incurring the precipitating event. Using the PRA, PJM can determine: the amount of risk each transformer poses to the system; the best way to mitigate each transformer's risk; the optimum number of spare transformers; where to locate them on the system; the value of moving a low-risk spare transformer to a higher risk location; the value of a common transformer design; and, the point at which the risk associated with continued operation of an older transformer unit exceeds the value of a new unit.
Programmable Logic Controller		PLC	An electronic device that is capable of being programmed with instructions to provide specific operating control over electrical equipment.
Reactive Power (expressed in MVAR)	M-14A		The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. Reactive power is usually expressed in megavars (MVAR).
Regional RTEP Project	M-14B OA		A transmission expansion or enhancement at a voltage level of 100 kV or higher.
Regional Transmission Expansion Plan	M-14B	RTEP	The plan prepared by PJM pursuant to Schedule 6 of the PJM Operating Agreement for the enhancement and expansion of the Transmission System in order to meet the demands for firm transmission service in the PJM Region.
Regional Transmission Organization	FERC	RTO	An independent, FERC-approved organization of sufficient regional scope, which coordinates the interstate movement of electricity under FERC-approved Tariffs by operating the transmission system and competitive wholesale electricity markets and ensuring reliability and efficiency through expansion planning and interregional coordination.
Reliability	NERC		A reliable bulk power system is one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the amount of available electricity. NERC divides reliability into "Adequacy" and "Security."

Term	Reference	Acronym	Definition
Reliability Assurance Agreement	RAA	RAA	The Reliability Assurance Agreement among load-serving entities in the PJM Region. This Agreement is intended to ensure that adequate Capacity Resources will be planned and made available to provide reliable service to loads within PJM, to assist other Parties during Emergencies and to coordinate planning of Capacity Resources consistent with the Reliability Principles and Standards.
Reliability Pricing Model		RPM	PJM's resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and load serving entity (LSE) obligations that is consistent with the PJM Regional Transmission Expansion Planning (RTEP) process. RPM adds stability and a locational nature to the pricing signal for capacity.
Reliability Must Run		RMR	A generation resource subject to the dispatch of PJM that, as a result of transmission constraints, PJM determines, in the exercise of Good Utility Practice, must be run in order to maintain reliability.
Reliability*First* Corporation		RFC	Reliability*First* is a not-for-profit company incorporated in the State of Delaware whose goal is to preserve and enhance electric service reliability and security for the interconnected electric systems within its territory. Reliability*First* was approved by the North American Electric Reliability Council (NERC) to become one of eight Regional Reliability Councils in North America and began operations on January 1, 2006. Reliability*First* is the successor organization to three former NERC Regional Reliability Councils: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR) and the Mid-American Interconnected Network organizations (MAIN).
Renewable Integration Study		RIS	Renewable Integration Study: The RIS is an ongoing study to examine the reliability and market impacts of high wind and solar penetration in the PJM system to meet objectives of state policies regarding renewable resource production.
Renewable Portfolio Standard		RPS	Guidelines or requirements at the state or federal level requiring energy suppliers to provide specified amounts of electric energy from eligible renewable energy resources.
Right of first refusal		ROFR or RFR	A contractual right that gives the holder the option to enter a business transaction with the owner of an asset, according to specified terms, before the owner is entitled to enter into that transaction with a third party
Right of Way		ROW	A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.
Security	NERC		The ability of the bulk power system to withstand sudden, unexpected disturbances such as short circuits, or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by man-made physical or cyber attacks. The bulk power system must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.
Southern Sub-Region	M-14B		The PJM Southern Sub-Region area comprises one transmission owner zone – Dominion Virginia Power (Dominion).
Special Protection System	M-03	SPS	A Special Protection System (SPS) - also known as a remedial action scheme -includes an assembly of protection devices designed to detect and initiate automatic action in response to abnormal or pre-defined system conditions. The intent of these schemes is generally to protect equipment from thermal overload or to protect against system instability following subsequent contingencies on the electric system. Redundant assemblies may be applied for the above functions on an individual facility—in such cases, each assembly is considered as a separate protection system. An SPS consists of protection devices such as relays, current transformers, potential transformers, communication interface equipment, communication links, breaker trip and close coils, switchgear auxiliary switches, and all associated connections.
Static Var Compensator		SVC	A rapidly operating device that can continuously provide the reactive power required to control dynamic voltage swings under various system conditions and thereby improve the power system transmission and distribution performance.
Sub-regional RTEP Committee	M-14B OA		A PJM committee that facilitates the development and review of the Sub-regional RTEP Projects. The Sub-regional RTEP Committee will be responsible for the initial review of the Sub-regional RTEP Projects, and to provide recommendations to the Transmission Expansion Advisory Committee concerning the Sub-regional RTEP Projects.
Sub-regional RTEP Project	M-14B OA		Defined in the PJM Operating Agreement as a transmission expansion or enhancement rated below 230 kV.

Term	Reference	Acronym	Definition
Supplemental Project	M-14B OA		Replaces the term "Transmission Owner Initiated or TOI Project." A Regional RTEP Project(s) or a Sub-regional RTEP Project(s), which is not required for compliance with the following PJM criteria: System reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection.
Surge Impedance Loading		SIL	The megawatt loading of a transmission line at which a natural reactive power balance occurs. A Line Loaded below its SIL supplies reactive power to the system; A line above its SIL absorbs reactive power
Temperature-Humidity Index	M-19	THI	Temperature-humidity index gives a single, numerical value in the general range of 70 to 80, reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. The temperature-humidity index, THI, is defined as follows: THI = Td – (0.55 – 0.55RH) * (Td - 58) where Td is the dry-bulb temperature and RH is the percentage of relative humidity.
Topology	M-14B		A geographically based or other diagrammatic representation of the physical features of an electrical system or portion of an electrical system - including transmission lines, transformers, substations, capacitors and other power system elements – that in aggregate constitute a transmission system model for power flow and economic analysis.
Transmission Customer	M-14A M-14B M-2 OATT		Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that PJM file with the FERC, a proposed unexecuted Service Agreement to receive transmission service under Part II of the PJM OATT.
Trans-Allegheny Interstate Line		TrAIL	A 500 kV backbone transmission line approved by the PJM Board in 2006 which will connect the 502 Junction substation in southwestern Pennsylvania with the Loudoun substation in northern Virginia.
Transmission Expansion Advisory Committee	M-14B	TEAC	A committee established by PJM to provide advice and recommendations to aid in the development of the Regional Transmission Expansion Plan. The Transmission Expansion Advisory Committee shall review and provide advice and recommendations on the Regional RTEP Projects and the Subregional RTEP Projects when in the judgment of PJM these projects are determined to substantially impact power flow(s) on the regional transmission facilities.
Transmission System	OATT		The transmission facilities operated by PJM used to provide transmission services. These facilities that transmit electricity: are within the PJM Region; meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities; and have been demonstrated to the satisfaction of PJM to be integrated with the transmission system of PJM and integrated into the planning and operation of such to serve all of the power and transmission customers within such region.
Transmission Loading Relief	M-03	TLR	A NERC procedure developed for the Eastern Interconnection to mitigate overloads on the transmission system by allowing reliability coordinators to request the curtailment of transactions that are causing parallel flows through their system.
Transmission Owner	M-14B OATT	TO	A PJM Member that owns Transmission Facilities or leases with rights equivalent to ownership in Transmission Facilities. Taking transmission service is not sufficient to qualify a Member as a Transmission Owner.
Transmission Provider	M-14B OATT		The Transmission Provider is PJM for all purposes in accordance with the PJM OATT.
Transmission Service Request	M-02	TSR	A request submitted by a PJM market participant for transmission service over PJM designated facilities. Typically the request is for either short term or long term service, over a specific path for a specific megawatt amount. PJM evaluates each request and determines if it can be accommodated, and, if the requestor so chooses, pursues needed upgrades to accommodate the request.
Unforced Capacity	RAA	UCAP	An entitlement to a specified number of summer rated MW of capacity from a specific resource, on average, not experiencing a forced outage or derating, for the purpose of satisfying capacity obligations imposed under the RAA.

Term	Reference	Acronym	Definition
Upgrade Construction Service Agreement		UCSA	The terms and conditions of an UCSA govern the construction activities associated with the upgrade of capability along an existing PJM bulk electric system circuit in order to accommodate a merchant transmission interconnection request. Facilities constructed under an UCSA are not owned by a developer. All ownership rights of the physical facilities are retained by the respective Transmission Owner following the completion of construction. PJM and the developer execute a separate UCSA with each impacted transmission owner. A developer retains the right, but not the obligation ("Option to Build"), to design, procure, construct and install all or any portion of the Direct Assignment Facilities and/or Customer-Funded Upgrades.
Violation	M-14B		A PJM planning study result that shows a specific system condition that is not in compliance with established NERC, Reliability*First*, SERC or PJM reliability criteria.
Weather Normalized Peak	M-19		An estimate of the seasonal peak load at normal peak day weather conditions.
Western Sub-Region	M-14B OA		The PJM Western Sub-Region comprises five transmission owner zones: Allegheny Power (AP), American Electric Power (AEP), American Transmission Systems Incorporated (ATSI), Commonwealth Edison (ComED), Dayton Power and Light (Dayton), Duke Energy Ohio and Kentucky (DEO&K) and Duquesne Light Company (DLCO).
Zone / Control Zone	M-14B		An area within the PJM Control Area, as set forth in the PJM Open Access Tariff and the Reliability Assurance Agreement (RAA). Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.