Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** As of December 31, 2014, 68,108.4 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 201,689.4 MW as of December 31, 2014. Of the capacity in queues, 8,729.4 MW, or 12.8 percent, are uprates and the rest are new generation. Wind projects account for 15,660.0 MW of nameplate capacity or 23.0 percent of the capacity in the queues. Combined-cycle projects account for 41,239.6 MW of capacity or 60.5 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-6, 26,679.8 MW have been, or are planned to be, retired between 2011 and 2019, with all but 2,140.8 MW planned to be retired by the end of 2015. The AEP Zone accounts for 6,024.0 MW, or 22.6 percent, of all MW planned for retirement from 2015 through 2019.
- **Generation Mix.** A significant change in the distribution of unit types within the PJM footprint is likely as natural gas fired units continue to be developed and steam units continue to be retired. While only 1,992.5 MW of coal fired steam capacity are currently in the queue, 9,222.8 MW of coal fired steam capacity are slated for deactivation. Most of these retirements, 7,894.8 MW, are scheduled to take place by June 1, 2015, in large part due to the EPA's Mercury and Air Toxics Standards (MATS). In contrast, 43,697.3 MW of gas fired capacity are in the queue, while only 1,951 MW of natural gas units are planned to retire. The replacement of steam units by units burning natural gas could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[1] The process is complex and time consuming as a result of the nature of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants.
- The queue contains a substantial number of projects that are not likely to be built. These projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- Many feasibility, impact and facilities studies are delayed for reasons including disputes with developers, circuit and network issues, retooling as a result of projects being withdrawn, and an accumulated backlog of incomplete studies.
- Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation of the parent company of the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner.

Regional Transmission Expansion Plan (RTEP)

- Artificial Island is an area in southern New Jersey that includes nuclear units at Salem and at Hope Creek. On April 29, 2013, PJM issued a request for proposal (RFP), seeking technical solutions to improve stability issues, operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations in this area. PJM received 26 individual proposals from seven entities, including proposals from the incumbent transmission owner, PSE&G, and from non-incumbents. PJM actively engaged in an iterative process with Artificial Island

1 PJM. OATT Parts IV & VI.

project sponsors to modify the technical aspects of proposals and to allow updated cost estimates. The process has been controversial and is ongoing.

Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects intended to resolve a wide range of reliability criteria violations and congestion issues and which have substantial impacts on energy and capacity markets. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, Susquehanna-Roseland, and Surry Skiffes Creek 500kV.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outages according to rules in PJM's Manual 3 to decide if the outage is on time, late, or past its deadline.[2]

Recommendations

The MMU recommends improvements to the planning process.

- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[3] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Not Adopted.)
- The MMU recommends an analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported Q1, 2014. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to permit competition between incumbent transmission providers and nonincumbent providers. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM reevaluate transmission outage tickets when the outage is rescheduled. (Priority: Low. New recommendation. Status: Not adopted.)

2 PJM. "Manual 03: Transmission Operations," Revision 46 (December 1, 2014), Section 4.

3 See "Comments of the Independent Market Monitor for PJM," <*http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf*>.

Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in the affected area. In addition, despite Order No. 1000, there is not yet a robust and clearly defined mechanism to permit competition to build transmission projects or to obtain least cost financing through the capital markets.

The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The PJM queue evaluation process should be improved to ensure that barriers to competition are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management.

The PJM rules for competitive transmission development should build upon Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent providers. One way to do this is to consider utilities' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base. Because PJM now has the responsibility for planning the development of the grid under its RTEP process, property bought to facilitate future expansion should be a part of that process and be made available to all providers on equal terms.

Planned Generation and Retirements

Planned Generation Additions

Net revenues provide incentives to build new generation to serve PJM markets. While these incentives operate with a significant time lag and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. On December 31, 2014, 68,108.4 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 201,689.4 MW as of December 31, 2014. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 12-1). In 2014, 2,659.0 MW of nameplate capacity were added in PJM.

Table 12-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through 2014

	MW
2000	505.0
2001	872.0
2002	3,841.0
2003	3,524.0
2004	1,935.0
2005	819.0
2006	471.0
2007	1,265.0
2008	2,776.7
2009	2,515.9
2010	2,097.4
2011	5,007.8
2012	2,669.4
2013	1,126.8
2014	2,659.0

PJM Generation Queues

Generation request queues are groups of proposed projects, including new units, reratings of existing units, capacity resources and energy only resources. Each queue is open for a fixed amount of time. Studies commence on all projects in a given queue when that queue closes. The duration of the queue period has varied. Queues A and B were open for a year. Queues C-T were open for six months. Starting in February 2008, Queues

U-Y1 were open for three months. Starting in May 2012, the duration of the queue period was set to six months, starting with Queue Y2. Queue AA2 is currently open.

All projects that have been entered in a queue have a status assigned. Projects listed as active are undergoing one of the studies (feasibility, system impact, facility) required to proceed. Other status options are under construction, suspended, and in-service. Withdrawn projects are removed from the queue and listed separately. A project cannot be suspended until it has reached the status of under construction. Any project that entered the queue before February 1, 2011, can be suspended for up to three years, at which point it is subject to termination of the Interconnection Service Agreement and corresponding cancellation costs. Projects that entered the queue after February 1, 2011 face an additional restriction in that the suspension period is reduced to one year if they affect any project later in the queue.[4]

Table 12-2 shows MW in queues by expected completion date and MW changes in the queues between September 30, 2014 and December 31, 2014 for ongoing projects, i.e. projects with the status active, under construction or suspended.[5] Projects that are already in service are not included here. The total MW in queues increased by 7,534.6 MW, or 12.4 percent, from 60,573.8 MW at the end of the third quarter of 2014. The change was the result of 10,237.7 MW in new projects entering the queue, 2,334.5 MW in existing projects withdrawing, and 397.3 MW going into service. The remaining difference is the result of projects adjusting their expected MW. More MW were added to the queue in the last quarter of 2014 than the 2,992.7 MW and 2,340.9 MW added in the prior two quarters of 2014. There were five large projects that contributed to this increase, including a 1,710 MW coal plant project to replace the Hatfield plant retired in October, 2013 and four natural gas projects that added a total of 3,962 MW to queue capacity.[6]

Table 12-2 Queue comparison by expected completion year (MW): September 30, 2014 vs. December 31, 2014[7]

	As of 9/30/2014	As of 12/31/2014	Quarterly Change (MW)	Quarterly Change (percent)
≤ 2013	0.0	0.0	0.0	NA
2014	5,321.4	4,604.5	(716.9)	(13.5%)
2015	13,098.3	13,992.5	894.2	6.8%
2016	15,484.3	16,974.2	1,489.8	8.8%
2017	11,958.1	14,075.1	2,117.0	15.0%
2018	11,891.5	12,587.0	695.5	5.5%
2019	1,148.0	3,051.0	1,903.0	62.4%
2020	78.2	1,152.0	1,073.8	93.2%
2021	0.0	78.2	78.2	100.0%
2024	1,594.0	1,594.0	0.0	0.0%
Total	60,573.8	68,108.4	7,534.6	12.4%

Table 12-3 shows the yearly project status changes in more detail and how scheduled queue capacity has changed between September 30, 2014 and December 31, 2014. For example, 10,397.7 MW entered the queue in the third quarter, 160.0 MW of which were withdrawn before the quarter ended. Of the total 36,722.1 MW marked as active at the beginning of this quarter, 2,273.7 MW were withdrawn, 70.0 MW were suspended, 2,754.6 MW started construction, and 65.2 went into service by the end of the fourth quarter. The "Under Construction" column shows that 3,010.6 MW began construction in the fourth quarter of 2014, in addition to the 18,617.0 MW of capacity that maintained the status "under construction" from the previous quarter.

4 See PJM. Manual 14C. "Generation and Transmission Interconnection Process," Revision 8 (December 20, 2012), Section 3.7, <http://www.pjm.com/~/media/documents/manuals/m14c.ashx>.

5 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

6 The queue data in this section are now based on PJM queue data while prior reports relied on public queue data only.

7 Wind and solar capacity in Table 12-2 through Table 12-5 have not been adjusted to reflect derating.

Table 12-3 Change in project status (MW): September 30, 2014 vs. December 31, 2014

		Status at 12/31/2014				
Status at 9/30/2013	Total at 9/30/2014	Active	Suspended	Under Construction	In Service	Withdrawn
(Entered in Q4 2014)		10,237.7	0.0	0.0	0.0	160.0
Active	36,722.1	31,491.3	70.0	2,754.6	65.2	2,273.7
Suspended	4,501.8	0.0	4,341.8	256.0	0.0	0.0
Under Construction	19,349.9	0.0	340.0	18,617.0	332.1	60.8
In Service	38,053.4	0.0	0.0	0.0	37,944.4	43.0
Withdrawn	269,264.9	0.0	0.0	0.0	0.0	272,093.1
Total at 12/31/2014		41,729.0	4,751.8	21,627.6	38,341.7	274,630.6

Table 12-4 Capacity in PJM queues (MW): At December 31, 2014[8]

Queue	Active	In-Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	8,103.0	0.0	0.0	17,347.0	25,450.0
B Expired 31-Jan-99	0.0	4,645.5	0.0	0.0	15,832.7	20,478.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	4,151.2	4,682.2
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,770.0	8,620.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	16,886.8	17,682.0
F Expired 31-Jan-01	0.0	52.0	0.0	0.0	3,092.5	3,144.5
G Expired 31-Jul-01	0.0	1,189.6	0.0	0.0	22,013.9	23,203.5
H Expired 31-Jan-02	0.0	702.5	0.0	0.0	8,421.9	9,124.4
I Expired 31-Jul-02	0.0	103.0	0.0	0.0	3,738.3	3,841.3
J Expired 31-Jan-03	0.0	40.0	0.0	0.0	846.0	886.0
K Expired 31-Jul-03	0.0	218.0	0.0	0.0	2,425.5	2,643.5
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	0.0	504.8	150.0	0.0	3,705.6	4,360.4
N Expired 31-Jan-05	0.0	2,398.8	38.0	0.0	8,090.3	10,527.0
O Expired 31-Jul-05	0.0	1,688.2	225.0	212.0	5,466.8	7,592.0
P Expired 31-Jan-06	0.0	3,255.2	62.5	210.0	5,110.5	8,638.2
Q Expired 31-Jul-06	105.0	3,147.9	1,594.0	0.0	9,686.7	14,533.6
R Expired 31-Jan-07	0.0	1,386.4	1,668.3	300.0	19,400.6	22,755.3
S Expired 31-Jul-07	0.0	3,301.3	644.3	490.0	12,706.5	17,142.0
T Expired 31-Jan-08	1,010.0	1,310.0	3,048.0	0.0	22,188.3	27,556.3
U Expired 31-Jan-09	1,430.0	925.3	567.0	459.9	29,974.6	33,356.8
V Expired 31-Jan-10	1,772.4	1,812.8	1,469.3	148.0	12,169.4	17,371.9
W Expired 31-Jan-11	2,648.0	650.4	1,999.4	1,923.5	17,093.6	24,314.9
X Expired 31-Jan-12	5,250.8	322.0	7,457.6	395.8	16,942.0	30,368.2
Y Expired 30-Apr-13	6,729.7	212.5	2,460.1	592.6	16,023.3	26,018.0
Z Expired 30-Apr-14	9,527.9	107.4	244.2	20.0	4,789.1	14,688.6
AA1 Expired 31-Oct-14	12,844.8	0.0	0.0	0.0	166.0	13,010.8
AA2 through 31-Dec-14	410.5	0.0	0.0	0.0	0.0	410.5
Total	41,729.0	38,509.7	21,627.6	4,751.8	290,072.8	396,690.9

Table 12-4 shows the amount of capacity active, in-service, under construction, suspended, or withdrawn for each queue since the beginning of the regional transmission expansion plan (RTEP) process and the total amount of capacity that had been included in each queue. All items in queues A-L are either in service or have been withdrawn. As of December 31, 2014, there are 68,108.4 MW of capacity in queues that are not yet in service, of which 7.0 percent is suspended and 31.8 percent is under construction. The remaining 61.3 percent, or 41,729.0 MW, have not yet begun construction.

8 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

Distribution of Units in the Queues

Table 12-5 shows the projects under construction, suspended, or active as of December 31, 2014, by unit type, control zone and LDA.[9] As of December 31, 2014, 68,108.4MW of capacity were in generation request queues for construction through 2024, compared to 60,573.8 MW at September 30, 2014.[10] Table 12-5

9 Unit types designated as reciprocating engines are classified here as diesel.

10 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of installed capacity until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent of installed capacity until there is operational data to support a different conclusion. PJM derates solar resources to 38 percent of installed capacity. Based on the derating of 15,660.1 MW of wind resources and 2,978.0 MW of solar resources, the 68,108.4 MW currently active in the queue would be reduced to 52,637.8 MW.

also shows the planned retirements for each zone. The geographic distribution of generation in the queues shows that new capacity is being added in all LDAs, but planned retirements are more prevalent in EMAAC than in SWMACC and WMAAC. The net effect is that, by 2024, capacity in WMAAC will increase by more than it will increase in EMAAC and SWMAAC.

A significant change in the distribution of unit types within the PJM footprint is likely as natural gas fired units continue to be developed and steam units continue to be retired. While only 1,992.5 MW of coal fired steam capacity are currently in the queue, 9,222.8 MW of coal fired steam capacity are slated for deactivation. Most of these retirements, 7,894.8 MW, are scheduled to take place by June 1, 2015, in large part due to the EPA's Mercury and Air Toxics Standards (MATS). Although the MATS deadline is April 16, 2015, some units were granted a 45-day extension. In contrast, 43,697.3 MW of gas fired capacity are in the queue while only 1,951.0 MW of natural gas units are planned to retire. The replacement of older steam units by units burning natural gas could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Planned Retirements

As shown in Table 12-6, 26,679.8 MW is planned to be retired between 2011 and 2019, with all but 2,140.8 MW retired by the end of 2015. The AEP Zone accounts for 6,024.0 MW, or 22.6 percent, of all MW planned for deactivation from 2015 through 2019. Table 12-6 shows 323.0 MW still pending for 2014. This value reflects the pending deactivation of two Dominion units, which were scheduled to retire on December 31, 2014. It was determined that these units are required for reliability so their deactivation has been postponed. A map of retirements between 2011 and 2019 is shown in Figure 12-1, and a detailed list of pending deactivations is shown in Table 12-7.

Table 12-6 Summary of PJM unit retirements (MW): 2011 through 2019

	MW
Retirements 2011	1,129.2
Retirements 2012	6,961.9
Retirements 2013	2,862.6
Retirements 2014	2,949.3
Planned Retirements 2014	323.0
Planned Retirements 2015	10,313.0
Planned Retirements Post-2015	2,140.8
Total	26,679.8

Table 12-5 Queue capacity by control zone and LDA (MW) at December 31, 2014[11]

LDA	Zone	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total Queue Capacity	Planned Retirements
EMAAC	AECO	1,486.0	302.8	0.0	0.0	0.0	72.7	0.0	0.0	373.0	2,234.5	206.2
	DPL	1,301.2	17.0	0.0	0.0	0.0	450.3	19.9	2.0	279.0	2,069.4	34.0
	JCPL	2,555.0	0.0	0.0	0.0	0.0	673.1	0.0	40.0	0.0	3,268.1	1,084.5
	PECO	1,054.5	10.0	3.7	0.0	330.0	0.0	0.0	0.0	0.0	1,398.2	0.0
	PSEG	3,187.9	286.0	10.6	0.0	0.0	169.6	3.0	3.0	0.0	3,660.1	2,139.0
	EMAAC Total	9,584.6	615.8	14.3	0.0	330.0	1,365.7	22.9	45.0	652.0	12,630.3	3,463.7
SWMAAC	BGE	0.0	256.0	29.0	0.4	0.0	25.0	132.0	0.0	0.0	442.4	74.0
	Pepco	2,614.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,614.5	1,204.0
	SWMAAC Total	2,614.5	256.0	29.0	0.4	0.0	25.0	132.0	0.0	0.0	3,056.9	1,278.0
WMAAC	Met-Ed	800.0	91.5	0.0	0.0	35.0	3.0	401.0	0.0	0.0	1,330.5	0.0
	PENELEC	2,517.0	612.2	61.8	45.3	0.0	13.5	0.0	47.5	418.6	3,715.8	603.0
	PPL	5,317.0	0.0	5.0	0.0	0.0	129.0	16.0	60.0	899.0	6,426.0	0.0
	WMAAC Total	8,634.0	703.7	66.8	45.3	35.0	145.5	417.0	107.5	1,317.6	11,472.3	603.0
Non-MAAC	AEP	5,724.0	51.0	18.0	19.5	102.0	98.4	245.0	68.0	7,287.8	13,613.7	5,367.0
	APS	2,691.4	12.0	99.6	77.0	0.0	107.8	1,717.2	11.0	964.6	5,680.5	0.0
	ATSI	3,912.0	0.4	1.7	0.0	0.0	0.0	135.0	0.0	518.0	4,567.1	737.3
	ComEd	1,970.0	593.3	15.3	22.7	0.0	15.0	27.0	100.6	3,428.0	6,171.9	251.0
	DAY	0.0	0.0	1.9	112.0	0.0	23.4	32.5	20.0	300.0	489.8	271.8
	DEOK	513.0	0.0	0.0	0.0	0.0	40.0	50.0	20.0	0.0	623.0	163.0
	DLCO	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.0	124.0
	Dominion	5,256.1	62.0	11.0	0.0	1,594.0	1,157.2	62.5	128.0	1,192.1	9,462.9	323.0
	EKPC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	195.0
	Essential Power	135.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	135.0	0.0
	Non-MAAC Total	20,406.5	718.7	147.5	231.2	1,696.0	1,441.8	2,269.2	347.6	13,690.5	40,948.9	7,432.1
Total		41,239.6	2,294.2	257.6	276.8	2,061.0	2,978.0	2,841.1	500.1	15,660.1	68,108.4	12,776.8

11 This data includes only projects with a status of active, under-construction, or suspended.

Figure 12-1 Map of PJM unit retirements: 2011 through 2019

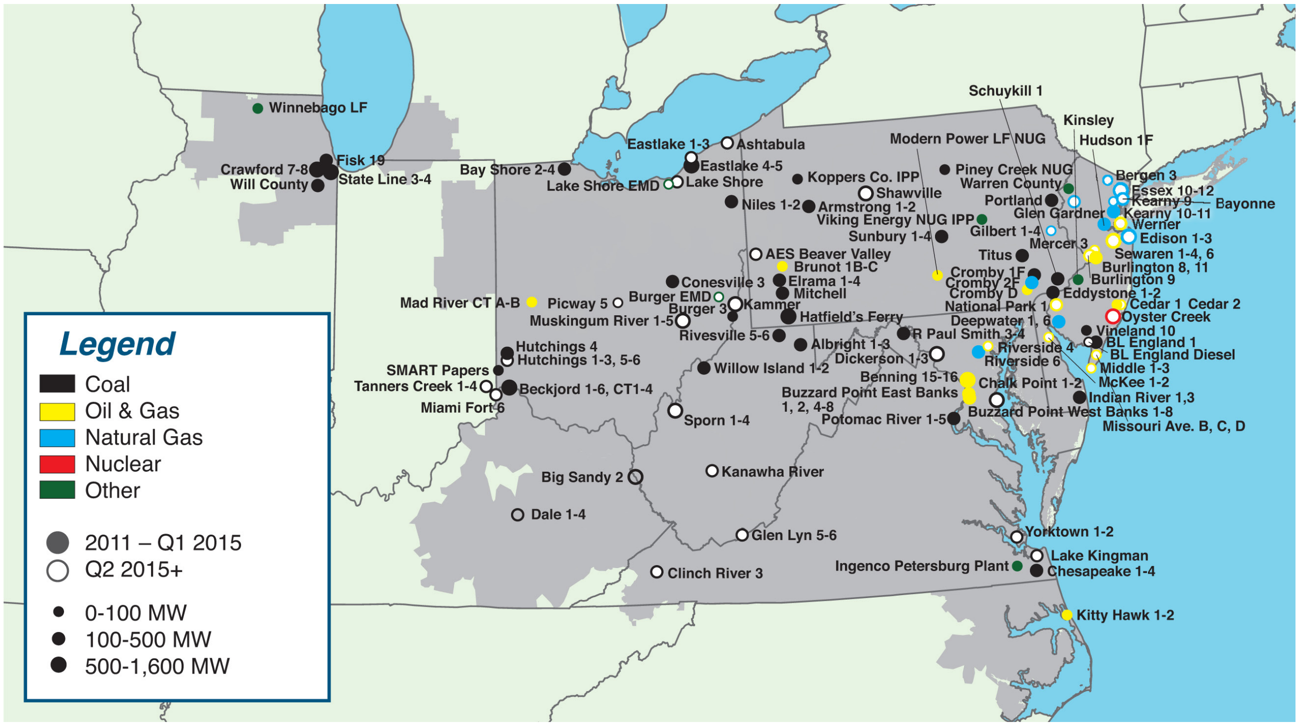


Table 12-7 Planned deactivations of PJM units, as of December 31, 2014

Unit	Zone	MW	Fuel	Unit Type	Projected Deactivation Date
Yorktown 1-2	Dominion	323.0	Coal	Steam	31-Dec-14
Eastlake 1-3	ATSI	327.0	Coal	Steam	15-Apr-15
Lake Shore 18	ATSI	190.0	Coal	Steam	15-Apr-15
Lake Shore EMD	ATSI	4.0	Diesel	Diesel	15-Apr-15
Will County	ComEd	251.0	Coal	Steam	15-Apr-15
Dale 1-4	EKPC	195.0	Coal	Steam	16-Apr-15
Shawville 1-4	PENELEC	603.0	Coal	Steam	16-Apr-15
Gilbert 1-4	JCPL	98.0	Natural gas	Combustion Turbine	01-May-15
Glen Gardner 1-8	JCPL	160.0	Natural gas	Combustion Turbine	01-May-15
Kearny 9	PSEG	21.0	Natural gas	Combustion Turbine	01-May-15
Werner 1-4	JCPL	212.0	Light oil	Combustion Turbine	01-May-15
Cedar 1-2	AECO	65.6	Kerosene	Combustion Turbine	31-May-15
Essex 12	PSEG	184.0	Natural gas	Combustion Turbine	31-May-15
Middle 1-3	AECO	74.7	Kerosene	Combustion Turbine	31-May-15
Missouri Ave B, C, D	AECO	57.9	Kerosene	Combustion Turbine	31-May-15
Ashtabula	ATSI	210.0	Coal	Steam	01-Jun-15
Bergen 3	PSEG	21.0	Natural gas	Combustion Turbine	01-Jun-15
Big Sandy 2	AEP	800.0	Coal	Steam	01-Jun-15
Burlington 8, 11	PSEG	205.0	Kerosene	Combustion Turbine	01-Jun-15
Clinch River 3	AEP	230.0	Coal	Steam	01-Jun-15
Edison 1-3	PSEG	504.0	Natural gas	Combustion Turbine	01-Jun-15
Essex 10-11	PSEG	352.0	Natural gas	Combustion Turbine	01-Jun-15
Glen Lyn 5-6	AEP	325.0	Coal	Steam	01-Jun-15
Hutchings 1-3, 5-6	DAY	271.8	Coal	Steam	01-Jun-15
Kammer 1-3	AEP	600.0	Coal	Steam	01-Jun-15
Kanawha River 1-2	AEP	400.0	Coal	Steam	01-Jun-15
Mercer 3	PSEG	115.0	Kerosene	Combustion Turbine	01-Jun-15
Miami Fort 6	DEOK	163.0	Coal	Steam	01-Jun-15
Muskingum River 1-5	AEP	1,355.0	Coal	Steam	01-Jun-15
National Park 1	PSEG	21.0	Kerosene	Combustion Turbine	01-Jun-15
Picway 5	AEP	95.0	Coal	Steam	01-Jun-15
Riverside 4	BGE	74.0	Natural gas	Steam	01-Jun-15
Sewaren 1-4,6	PSEG	558.0	Kerosene	Combustion Turbine	01-Jun-15
Sporn 1-4	AEP	580.0	Coal	Steam	01-Jun-15
Tanners Creek 1-4	AEP	982.0	Coal	Steam	01-Jun-15
BL England Diesels	AECO	8.0	Diesel	Diesel	01-Oct-15
Burger EMD	ATSI	6.3	Diesel	Diesel	31-May-16
McKee 1-2	DPL	34.0	Heavy Oil	Combustion Turbine	31-May-17
AES Beaver Valley	DLCO	124.0	Coal	Steam	01-Jun-17
Chalk Point 1-2	Pepco	667.0	Coal	Steam	31-May-18
Dickerson 1-3	Pepco	537.0	Coal	Steam	31-May-18
Bayonne Cogen Plant (CC)	PSEG	158.0	Natural gas	Steam	01-Nov-18
Oyster Creek	JCPL	614.5	Nuclear	Steam	31-Dec-19
Total		12,776.8			

Table 12-8 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2019. The majority, 77.4 percent of all MW retiring during this period are coal steam units. These units have an average age of 56.4 years and an average size of 166.6 MW. This indicates that on average, retirements have consisted of smaller sub-critical coal steam units and those without adequate environmental controls to remain viable beyond 2015.

Table 12-8 Retirements by fuel type, 2011 through 2019

	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Coal	124	166.6	56.4	20,659.6	77.4%
Diesel	7	11.0	43.9	77.2	0.3%
Heavy Oil	4	68.5	57.3	274.0	1.0%
Kerosene	20	41.4	45.5	828.2	3.1%
LFG	15	76.6	43.8	1,148.7	4.3%
Light Oil	4	6.5	14.8	26.1	0.1%
Natural Gas	50	59.9	46.4	2,996.5	11.2%
Nuclear	1	614.5	50.0	614.5	2.3%
Waste Coal	1	31.0	20.0	31.0	0.1%
Wood Waste	2	12.0	23.5	24.0	0.1%
Total	228	117.0	50.8	26,679.8	100.0%

Actual Generation Deactivations in 2014

Table 12-9 shows the units that were deactivated in 2014.[12]

Table 12-9 Unit deactivations in 2014

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Average Age (Years)	Retirement Date
First Energy	Mad River CTs A	25.0	Diesel	ATSI	41	09-Jan-14
First Energy	Mad River CTs B	25.0	Diesel	ATSI	41	09-Jan-14
Duke Energy	Walter C Beckjord 4	150.0	Coal	DEOK	56	17-Jan-14
Modern Mallard Energy	Modern Power Landfill NUG	8.0	LFG	Met-Ed	56	03-Feb-14
Rockland Capital	BL England 1	113.0	Coal	AECO	51	01-May-14
Calpine Corporation	Deepwater 1	78.0	Natural gas	AECO	55	31-May-14
Calpine Corporation	Deepwater 6	80.0	Natural gas	AECO	60	01-Jun-14
NRG Energy	Portland 1	158.0	Coal	Met-Ed	56	01-Jun-14
NRG Energy	Portland 2	243.0	Coal	Met-Ed	52	01-Jun-14
Exelon Corporation	Riverside 6	115.0	Natural gas	BGE	44	01-Jun-14
PSEG	Burlington 9	184.0	Kerosene	PSEG	42	01-Jun-14
Corona Power	Sunbury 1-4	347.0	Coal	PPL	63	18-Jul-14
Integrys Energy	Winnebago Landfill	6.4	LFG	ComEd	07	01-Nov-14
Duke Energy	Walter C Beckjord 5-6	652.0	Coal	DEOK	49	01-Oct-14
Dominion	Chesapeake 1-4	576.0	Coal	Dominion	57	23-Dec-14
Duke Energy	Walter C Beckjord GT1-4	188.0	Coal	DEOK	43	25-Dec-14
PSEG	Kinsley Landfill	0.9	LFG	PSEG	30	31-Dec-14
Total		2,949.3				

Generation Mix

As of December 31, 2014, PJM had an installed capacity of 201,689.4 MW (Table 12-10). This measure differs from capacity market installed capacity because it includes energy-only units, uses non-derated values for solar and wind resources, and does not include external units.

Table 12-10 Existing PJM capacity: At December 31, 2014 (By zone and unit type (MW))[13]

Zone	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	901.9	705.9	22.6	0.0	0.0	0.0	41.7	815.9	0.0	7.5	2,495.5
AEP	4,900.0	3,682.2	77.1	0.0	1,071.9	2,071.0	0.0	24,264.8	4.0	1,953.2	38,024.2
APS	1,129.0	1,214.9	47.9	0.0	86.0	0.0	36.1	5,409.0	27.4	1,058.5	9,008.8
ATSI	685.0	1,617.4	74.0	0.0	0.0	2,134.0	0.0	6,540.0	0.0	0.0	11,050.4
BGE	0.0	720.0	18.4	0.0	0.0	1,716.0	0.0	2,995.5	0.0	0.0	5,449.9
ComEd	2,270.1	7,244.0	100.2	0.0	0.0	10,473.5	9.0	5,417.1	4.5	2,431.9	27,950.3
DAY	0.0	1,368.5	47.5	0.0	0.0	0.0	1.1	3,179.8	40.0	0.0	4,636.9
DEOK	47.2	842.0	0.0	0.0	0.0	0.0	0.0	4,382.0	0.0	0.0	5,271.2
DLCO	244.0	15.0	0.0	0.0	6.3	1,777.0	0.0	784.0	0.0	0.0	2,826.3
Dominion	5,493.6	3,874.8	153.8	0.0	3,589.3	3,581.3	2.7	8,403.0	0.0	0.0	25,098.5
DPL	1,189.3	1,820.4	96.1	30.0	0.0	0.0	4.0	1,620.0	0.0	0.0	4,759.8
EKPC	0.0	774.0	0.0	0.0	70.0	0.0	0.0	1,882.0	0.0	0.0	2,726.0
EXT	1,471.0	297.9	0.0	0.0	269.1	12.5	0.0	5,253.5	0.0	0.0	7,304.0
JCPL	1,692.5	1,233.1	16.1	0.0	400.0	614.5	96.3	10.0	0.0	0.0	4,062.5
Met-Ed	2,111.0	406.5	41.4	0.0	19.0	805.0	0.0	200.0	0.0	0.0	3,582.9
PECO	3,209.0	836.0	2.9	0.0	1,642.0	4,546.8	3.0	979.1	1.0	0.0	11,219.8
PENELEC	0.0	407.5	45.8	0.0	512.8	0.0	0.0	6,793.5	0.0	930.9	8,690.5
Pepco	1,807.9	616.2	60.5	0.0	706.6	2,520.0	15.0	5,169.9	20.0	219.7	11,135.8
PPL	3,091.3	2,653.8	12.0	0.0	5.0	3,493.0	108.2	2,050.1	2.0	0.0	11,415.4
PSEG	230.0	1,091.7	9.9	0.0	0.0	0.0	0.0	3,649.1	0.0	0.0	4,980.7
Total	30,472.8	31,421.8	826.2	30.0	8,378.0	33,744.6	317.1	89,798.3	98.9	6,601.7	201,689.4

12 See PJM. "*PJM Generator Deactivations*," <http://www.pjm.com/planning/generation-deactivation/gd-summaries.aspx> (Accessed January 05, 2015).

13 The capacity described in this section refers to all non-derated installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 12-11 PJM capacity (MW) by age (years): at December 31, 2014

Age (years)	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 16	24,285.3	19,118.2	507.5	30.0	141.6	0.0	317.1	3,755.4	98.9	6,601.7	54,855.7
16 to 30	5,655.5	5,343.4	113.5	0.0	3,318.2	10,224.5	0.0	7,879.1	0.0	0.0	32,534.2
31 to 45	532.0	4,817.8	73.9	0.0	722.0	22,905.6	0.0	45,038.6	0.0	0.0	74,089.9
46 to 60	0.0	2,142.4	129.3	0.0	2,575.0	614.5	0.0	28,745.9	0.0	0.0	34,207.1
61 to 75	0.0	0.0	2.0	0.0	428.9	0.0	0.0	4,230.3	0.0	0.0	4,661.2
76 and over	0.0	0.0	0.0	0.0	1,192.3	0.0	0.0	149.0	0.0	0.0	1,341.3
Total	30,472.8	31,421.8	826.2	30.0	8,378.0	33,744.6	317.1	89,798.3	98.9	6,601.7	201,689.4

Figure 12-2 PJM capacity (MW) by age (years): at December 31, 2014

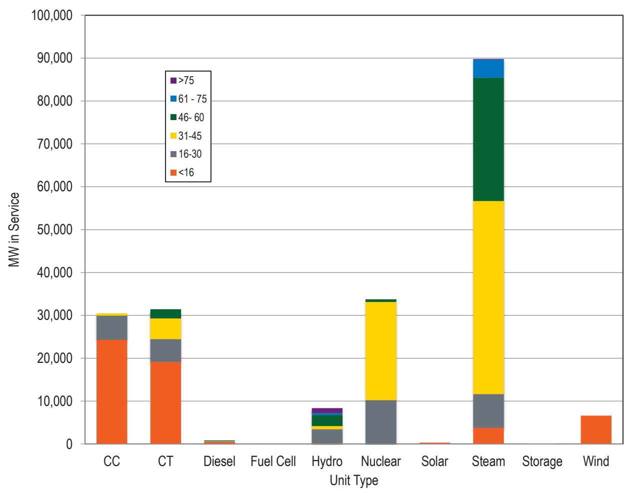


Figure 12-2 and Table 12-11 show the age of PJM generators by unit type. Units older than 30 years comprise 110,568.5 MW, or 55.4 percent, of the total capacity of 201,689.4 MW. Units older than 45 years comprise 40,209.6 MW, or 19.9 percent of the total capacity.

Table 12-12 shows the effect that expected retirements and new generation in the queues would have on the existing generation mix, noting the generators in excess of 40 years of age as of December 31, 2014, which are likely to retire by 2024. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generation. Existing capacity in SWMAAC is currently 63.7 percent steam; this would be reduced to 45.0 percent by 2024. CC and CT generators would comprise 40.2 percent of total capacity in SWMAAC in 2024.

In Non-MAAC zones, 81.1 percent of all generation 40 years or older, as of December 31, 2014, is steam, primarily coal.[14] If the older coal units retire and if all queued wind MW are built as planned, by 2024, wind farms would account for 11.4 percent of total non-derated ICAP MW in Non-MAAC zones.

14 Non-MAAC zones consist of the AEP, AP, ATSI, ComEd, DAY, DEOK, DLCO, and Dominion control zones.

Table 12-12 Comparison of generators 40 years and older with slated capacity additions (MW) through 2024, as of December 31, 2014[15]

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Planned Additions	Planned Retirements	Estimated Capacity 2024	Percent of Area Total
EMAAC	Combined Cycle	198.0	1.6%	10,084.0	29.7%	9,584.6	0.0	19,668.6	45.6%
	Combustion Turbine	4,041.8	31.8%	7,249.2	21.4%	615.8	2,196.2	5,668.8	13.1%
	Diesel	58.9	0.5%	149.7	0.4%	14.3	8.0	156.0	0.4%
	Fuel Cell	0.0	0.0%	30.0	0.1%	0.0	0.0	30.0	0.1%
	Hydroelectric	2,042.0	16.0%	2,047.0	6.0%	0.0	0.0	2,047.0	4.7%
	Nuclear	2,865.3	22.5%	8,654.3	25.5%	330.0	0.0	8,984.3	20.8%
	Solar	0.0	0.0%	253.2	0.7%	1,365.7	0.0	1,618.9	3.8%
	Steam	3,523.0	27.7%	5,475.1	16.1%	22.9	1,259.5	4,238.5	9.8%
	Storage	0.0	0.0%	3.0	0.0%	45.0	0.0	48.0	0.1%
	Wind	0.0	0.0%	7.5	0.0%	652.0	0.0	659.5	1.5%
	EMAAC Total	12,729.0	100.0%	33,953.0	100.0%	12,630.3	3,463.7	43,119.6	100.0%
SWMAAC	Combined Cycle	0.0	0.0%	230.0	2.2%	2,614.5	0.0	2,844.5	23.3%
	Combustion Turbine	873.3	15.0%	1,811.7	17.4%	256.0	0.0	2,067.7	16.9%
	Diesel	0.0	0.0%	28.3	0.3%	29.0	0.0	57.3	0.5%
	Hydroelectric	0.0	0.0%	0.0	0.0%	0.4	0.0	0.4	0.0%
	Nuclear	866.0	14.8%	1,716.0	16.5%	0.0	0.0	1,716.0	14.1%
	Solar	0.0	0.0%	0.0	0.0%	25.0	0.0	25.0	0.2%
	Steam	4,098.5	70.2%	6,644.6	63.7%	132.0	1,278.0	5,498.6	45.0%
	SWMAAC Total	5,837.8	100.0%	10,430.6	100.0%	3,056.9	1,278.0	12,209.5	100.0%
WMAAC	Combined Cycle	0.0	0.0%	3,918.9	16.7%	8,634.0	0.0	12,552.9	36.6%
	Combustion Turbine	713.5	6.7%	1,430.2	6.1%	703.7	0.0	2,133.9	6.2%
	Diesel	46.2	0.4%	147.7	0.6%	66.8	6.0	208.5	0.6%
	Hydroelectric	887.2	8.3%	1,238.4	5.3%	45.3	0.0	1,283.7	3.7%
	Nuclear	805.0	7.5%	3,325.0	14.2%	35.0	0.0	3,360.0	9.8%
	Solar	0.0	0.0%	15.0	0.1%	145.5	0.0	160.5	0.5%
	Steam	8,225.5	77.0%	12,163.4	52.0%	417.0	597.0	11,983.4	35.0%
	Storage	0.0	0.0%	20.0	0.1%	107.5	0.0	127.5	0.4%
	Wind	0.0	0.0%	1,150.6	4.9%	1,317.6	0.0	2,468.2	7.2%
	WMAAC Total	10,677.4	100.0%	23,409.2	100.0%	11,472.3	603.0	34,278.5	100.0%
Non-MAAC	Combined Cycle	244.0	0.5%	16,239.9	12.1%	20,406.5	0.0	36,646.4	21.9%
	Combustion Turbine	1,250.6	2.5%	20,930.7	15.6%	718.7	0.0	21,649.4	12.9%
	Diesel	71.8	0.1%	500.5	0.4%	147.5	10.3	637.7	0.4%
	Hydroelectric	1,702.0	3.4%	5,092.6	3.8%	231.2	0.0	5,323.8	3.2%
	Nuclear	6,301.9	12.4%	20,049.3	15.0%	1,696.0	0.0	21,745.3	13.0%
	Solar	0.0	0.0%	49.0	0.0%	1,441.8	0.0	1,490.8	0.9%
	Steam	41,179.7	81.1%	65,515.2	48.9%	2,269.2	7,421.8	60,362.6	36.1%
	Storage	0.0	0.0%	75.9	0.1%	347.6	0.0	423.5	0.3%
	Wind	0.0	0.0%	5,443.6	4.1%	13,690.5	0.0	19,134.1	11.4%
	Non-MAAC Total	50,750.0	100.0%	133,896.7	100.0%	40,948.9	7,432.1	167,413.5	100.0%
All Areas	Total	79,994.2		201,689.4		68,108.4	12,776.8	257,021.0	

15 Percentages shown in Table 12-12 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Generation and Transmission Interconnection Planning Process

PJM made changes to the queue process in May 2012.[16] These changes included reducing the length of the queues, creating an alternate queue for some small projects, and adjustments to the rules regarding suspension rights and Capacity Interconnection Rights (CIR).

Small Generator Interconnection

Due to the growing number of small generating facilities, FERC issued Order No. 2006 to extend interconnection service to devices used for the production of electricity having a capacity of no more than 20 MW and established the Small Generator Interconnection Procedures (SGIP) and a Small Generator Interconnection Agreement (SGIA).[17] The SGIP and SGIA are consistent with the standard Large Generator Interconnection Procedures document (LGIP) and standard Large Generator Interconnection Agreement (LGIA) for generating facilities larger than 20 MW, established in FERC Order No. 2003.[18]

FERC Order No. 792 was issued on November 22, 2013, to make several amendments to the SGIP and SGIA.[19] One revision is a provision for the option of a pre-application report of existing information about system conditions at a possible Point of Interconnection. This order also increases the threshold to participate in the Fast Track Process from 2 MW to 5 MW, but only for inverter-based machines.[20] The thresholds for all other eligible types (synchronous & induction) will remain at 2 MW. Another revision is to the customer options meeting and the supplemental review following the failure of the Fast Track screens so that the supplemental review is performed at the discretion of the Interconnection Customer.[21] This includes minimum load and other screens to determine if a Small Generating Facility may be interconnected safely and reliably. In addition, the SGIP Facilities Study Agreement will be revised to allow written comments to the Transmission Provider, similar to what is currently allowed for large generator projects. Finally, the SGIP and SGIA will now specifically include energy storage devices.[22] PJM filed these revisions to the OATT with FERC on August 4, 2014.23 No protests or comments were filed. An order is pending.

Interconnection Study Phase

In the study phase of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of projects in the queue. Table 12-13 shows an overview of PJM's study process. In addition to these steps, system impact and facilities studies are often redone when a project is withdrawn in order to determine the impact on the projects remaining in the queue.

PJM's Manual 14A states that it can take up to 739 days in addition to the (unspecified) time it takes to complete the facilities study to obtain an interconnection construction service agreement (CSA). It further states that a feasibility study should take no longer than 334 days from the day it entered the queue.[24] Manual 14B requires PJM to apply a commercial probability factor at the feasibility study stage to improve the accuracy of capacity and cost estimates. The commercial probability factor is based on the historical incidence of projects dropping out of the queue at the impact study stage.[25]

Table 12-14 shows the milestone due when projects were withdrawn, for all withdrawn projects.[26] Of the projects withdrawn, 49.7 percent were withdrawn before the Impact Study was completed.

16 See letter from PJM to Secretary Kimberly Bose, Docket No. ER12-1177-000, <*http://www.pjm.com/~/media/documents/ferc/2012-filings/20120229-er12-1177-000.ashx*>.

17 See *Standardization of Generator Interconnection Agreements and Procedures*, FERC Stats. & Regs. ¶31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 128 S. Ct. 1468 (2008).

18 See *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180 (2005), *order on reh'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005).

19 See *Small Generator Interconnection Agreements and Procedures*, 145 FERC ¶ 61,159 (2013) (Order No. 792).

20 See Order No. 792 at P 106.

21 See *Id.* at P 106.

22 See 145 FERC ¶ 61,159 at P 228 (2013).

23 See "PJM Compliance Filing," Docket No. ER14-2590-000 (August 4, 2014).

24 See PJM. Manual 14A. "Generation and Transmission Interconnection Process," Revision 15 (April 17, 2014), p.37.

25 See PJM. Manual 14B. "PJM Region Transmission Planning Process," Revision 27 (April 23, 2014), p.82.

26 In some cases, a Wholesale Market Participation Agreement (WMPA) is executed instead of an Interconnection Service Agreement (ISA).

Table 12-13 PJM generation planning process[27]

Process Step	Start on	Financial Obligation	Days for PJM to Complete	Days for Applicant to Decide Whether to Continue
Feasibility Study	Close of current queue	Cost of study (partially refundable deposit)	90	30
System Impact Study	Upon acceptance of the System Impact Study Agreement	Cost of study (partially refundable deposit)	120	30
Facilities Study	Upon acceptance of the Facilities Study Agreement	Cost of study (refundable deposit)	Varies	60
Schedule of Work	Upon acceptance of Interconnection Service Agreement (ISA)	Letter of credit for upgrade costs	Varies	37
Construction (only for new generation)	Upon acceptance of Interconnection Construction Service Agreement (ICSA)	None	Varies	NA

Table 12-14 Last milestone completed at time of withdrawal

Milestone Completed	Projects Withdrawn	Percent
Never Started	194	12.2%
Feasibility	596	37.5%
Impact	515	32.4%
Facility	98	6.2%
Interconnection Service Agreement (ISA)	136	8.6%
Construction Service Agreement (CSA) or beyond	49	3.1%
Total	1,588	100.0%

Table 12-15 and Table 12-16 show the time spent at various stages in the queue process and the completion time for the studies performed. For completed projects, there is an average time of 887 days, or 2.4 years, between entering a queue and going into service. Nuclear, hydro, and wind projects tend to take longer to go into service. The average time to go into service for all other fuel types is 753 days. For withdrawn projects, there is an average time of 654 days between entering a queue and withdrawing.

Table 12-15 Average project queue times (days) at December 31, 2014

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	1,060	710	59	3,890
In-Service	887	691	0	4,024
Suspended	1,914	697	699	3,652
Under Construction	1,736	883	367	6,380
Withdrawn	654	656	0	4,249

Table 12-16 presents information on the actual time in the stages of the queue for those projects not yet in service. Of the 549 projects in the queue as of December 31, 2014, 42 had a completed feasibility study and 186 were under construction.

27 Other agreements may also be required, e.g. Interconnection Construction Service Agreement (ICSA), Upgrade Construction Service Agreement (UCSA). See PJM. "Manual 14C: Generation and Transmission Interconnection Process," Revision 08 (December 20, 2012) p.29.

Table 12-16 PJM generation planning summary: at December 31, 2014

Milestone Completed	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Not Started	124	22.6%	102	458
Feasibility Study	42	7.7%	351	882
Impact Study	84	15.3%	1,107	3,160
Facility Study	21	3.8%	1,394	2,549
Interconnection Service Agreement (ISA)	18	3.3%	684	2,527
Construction Service Agreement (CSA)	3	0.5%	283	302
Under Construction	186	33.9%	1,413	3,811
Suspended	71	12.9%	1,647	3,587
Total	549	100.0%		

Regional Transmission Expansion Plan (RTEP)

Artificial Island

PJM has been seeking transmission solutions to improve stability and operational performance issues, as well to eliminate potential planning criteria violations in the Artificial Island Area, which includes the Salem and Hope Creek nuclear plants. PJM developed a new transmission expansion project solicitation process in two Order No. 1000 FERC compliance filings (dated October 25, 2012, and July 22, 2013), and described its approach as "utiliz[ing] the study process proposed under Order No. 1000."[28 29] PJM evaluated 26 proposals based on factors including siting, permitting, line crossings, outage requirements, and impacts to the Salem nuclear plant.

To date, PJM has engaged in an iterative process with Artificial Island project sponsors to modify the proposals and to allow updated cost estimates.

28 See "FERC Order 1000 Implementation" at <http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000.aspx>.

29 See PJM filing, Docket No. ER15-639-000 (Dec. 16, 2014) at 7.

The Transmission Expansion Advisory Committee (TEAC) recommended that PSE&G be selected to proceed with the Artificial Island project.[30] [31] On July 23, 2014, the PJM Board of Managers deferred the selection of a winner in order to review and address issues raised.[32]

On August 12, 2014, PJM requested additional information for five of the submitted proposals. The bidders for these proposals have been given the opportunity to supplement their proposals with updated cost estimates, as a result of PJM's modifications made during the initial evaluation.[33] All of the bidders responded by submitting the supplemental information requested.[34] PJM has engaged FERC's Alternative Dispute Resolution (ADR) process, which includes "an Administrative Law Judge present in a non-decisional role to ensure the fairness and due process" surrounding the final selection for this project.[35]

In a December 9, 2014, TEAC update on this project, PJM reported that input from permitting and regulatory entities had been gathered and additional constructability analysis and performance analysis had been conducted. The analysis includes a comparison of permitting and regulatory issues and a performance analysis. The selection process will also consider both the proposing entity's cost containment numbers as well as PJM cost estimates. A final selection has not yet been made.[36]

PJM's process has been controversial. On July 14, 2014, PHI and Exelon submitted a letter complaining "PJM adopted a sponsorship model ... and determine the best proposal amongst those submitted... PJM did not follow this process."[37] On January 29, 2015, PSEG filed a complaint alleging that PJM was not following the Order No. 1000 process, particularly objecting to the iterative nature of proposal development and the use of components of its proposal to enhance competing proposals.[38]

Other RTEP Proposals

The TEAC regularly reviews internal and external proposals to improve transmission reliability throughout PJM. On July 22, 2014, the PJM Board of Managers authorized $143.6 million to resolve baseline reliability violations. Subsequently, the RTEP proposal window 1, open from June 27 through July 28, 2014, yielded 106 baseline reliability projects proposals, encompassing 18 target transmission owner zones and 10 states.[39] None of these submissions were by a developer that was not a transmission owner. RTEP considered these proposals along with others reviewed at previous sub-regional RTEP (SRRTEP) and TEAC meetings that occurred between February and September, 2014. In the end, 22 projects were recommended by the TEAC and approved by the PJM Board All 22 projects were transmission owner upgrades with a total estimated cost of $81.5 million.[40]

The TEAC identified an additional $510 million in new baseline upgrades and changes to previously approved projects, as a result of the 2014 RTEP and 143 system impact studies performed on transmission planning projects. In addition, several immediate need reliability projects were also approved by the PJM Board.

RTEP's Proposal Window 2 closed on November 17, 2014, but an Addendum Proposal Window opened on January 20, 2015, because of a change in scope that will address a 2019 N-1-1 voltage drop. This window will remain open until February 3, 2015. In compliance with Order 1000, PJM also opened a Proposal Window on November 1, 2014, for all long term issues. It will remain open until February 27, 2017. For this window, PJM is using a multi-driver approach (MDA), and accepting proposals addressing not just long term

30 The TEAC Charter states: "PJM staff will be ultimately responsible for preparing and issuing all reports, running the committee meeting, management of data, final analytical work, and compilation and publication of other relevant documentation that may be required from time to time." <http://www.pjm.com/~/media/committees-groups/committees/teac/postings/teac-charter.ashx>.

31 See "Artificial Island Proposal Window," <http://pjm.com/~/media/committees-groups/committees/teac/20140616/20140616-teac-artificial-island-recommendation.ashx>, (June 16, 2014).

32 See Letter from Steve Herling, dated July 23, 2104 at <http://www.pjm.com/~/media/committees-groups/committees/teac/20140807/20140807-teac-artificial-island-letter.ashx>.

33 See Letter from Steve Herling, dated August 12, 2104 at <http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/august-12-2014-supplemental-request-letter.ashx>.

34 See "Supplemental Responses," at <http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows/closed-artificial-island-proposals.aspx>.

35 See Letter from Pauline Foley, dated August 29, 2104 at <http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/pjm-letter-to-chief-judge-wagner-regarding-artificial-island.ashx>.

36 See TEAC "Artificial Island" presentation at <http://www.pjm.com/~/media/committees-groups/committees/teac/20141209/20141209-artificial-island-update.ashx>.

37 See Letter from PHI/Exelon to Howard Schneider, Chair, PJM Board, re PJM Process for Evaluating Artificial Island Proposals, which can be accessed at: <https://www.pjm.com/~/media/about-pjm/who-we-are/public-disclosures/20140714-exelon-letter-regarding-the-pjm-process-for-evaluating-competitive-artificial-island-proposals.ashx> .

38 Complaint of Public Service Electric and Gas Company Against PJM Interconnection, L.L.C., Docket No. EL15-40-000.

39 See "Transmission Expansion Advisory Committee Reliability Analysis Update," September 25, 2014, at <http://www.pjm.com/~/media/committees-groups/committees/teac/20140925/20140925-reliability-analysis-update.ashx>.

40 See "Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board," November 11, 2014, at <http://www.pjm.com/~/media/committees-groups/committees/teac/20141111/20141111-board-approval-of-rtep-whitepaper.ashx>.

reliability, but also energy market efficiency, capacity market efficiency, and public policy.[41]

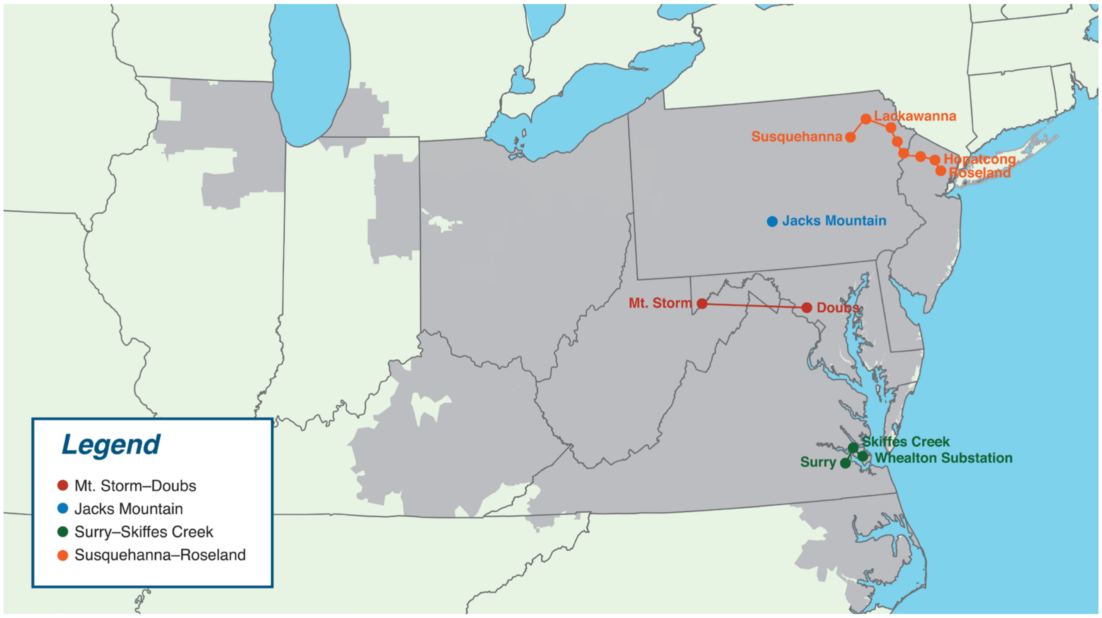
Consolidated Edison Company of New York, Inc. (Con Edison) Wheeling Contracts

A FERC order issued on September 6, 2010, reestablished the terms of an agreement between Con Edison and PJM to provide power to New York City that had been in place since the 1970s. Part of the settlement included an agreement by both parties that Con Edison would henceforth be subject to PJM RTEP costs, from which they had been previously exempt.[42] On December 11, 2013, the PJM Board approved changes to the RTEP, which included approximately $1.5 billion in additional baseline transmission enhancements and expansions.[43] PJM calculated Con Edison's cost responsibility assignment as approximately $629 million. On February 10, 2014, Con Edison filed a protest to the cost allocation proposal.[44] Con Edison asserted that the cost allocation proposal is not permitted under the service agreement for transmission service under the PJM Tariff and related settlement agreement, and that PJM's allocation of costs of the PSE&G upgrade to the Con Edison zone is unjust and unreasonable. On March 7, 2014, PJM submitted a motion for leave to answer and limited answer to the protest submitted by Con Edison.[45] PJM argued that the filed and approved RTEP cost allocation process was followed, and that Con Edison's cost assignment responsibilities were addressed by the Settlement agreement and Schedule 12 of the PJM Tariff.

Backbone Facilities

PJM baseline upgrade projects are implemented to resolve reliability criteria violations. PJM backbone projects are a subset of baseline upgrade projects that have been given the informal designation of backbone due to their relative significance. Backbone upgrades are on the extra high voltage (EHV) system and resolve a wide range of reliability criteria violations and market congestion issues. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, Susquehanna-Roseland, and Surry Skiffes Creek 500kV. Figure 12-3 shows the location of these four projects.

Figure 12-3 PJM Backbone Projects



41 See "Transmission Expansion Advisory Committee 2014 Market Efficiency Analysis," October 09, 2014, at <http://www.pjm.com/~/media/committees-groups/committees/teac/20141009/20141009-market-efficiency-analysis-update.ashx>.

42 132 FERC ¶ 61,221 p.8 (2010).

43 See the *2013 State of the Market Report for PJM*, Volume II, Section 12, "Planning," for a more detailed discussion.

44 See *Consolidated Edison Company of New York, Inc.* Docket No. ER14-972-000 (February 10, 2014).

45 See *PJM Interconnection L.L.C.* Docket No. ER14-972-000 (March 7, 2014).

The Mount Storm-Doubs transmission line, which serves West Virginia, Virginia, and Maryland, was originally built in 1966. The structures and equipment are approaching the end of their expected service life and require replacement to ensure reliability in its service areas. The first two phases, the line rebuild and the energizing of the Mount Storm switchyard, are complete. Construction plans for Phase 3, consisting of additional upgrades to the Mount Storm switchyard, are under development. Completion of this phase is expected by the end of 2015.[46]

The Jacks Mountain project is required to resolve voltage problems for load deliverability starting June 1, 2017. Jacks Mountain will be a new 500kV substation connected to the existing Conemaugh-Juniata and Keystone-Juniata 500kV circuits. Transmission foundations are planned for fall 2015. Below grade construction of the sub-station is scheduled to be completed by September 2016, and above grade, relay/control construction, is planned for October 2016-June 2017.[47]

The Susquehanna-Roseland project is required to resolve reliability criteria violations starting June 1, 2012. Susquehanna-Roseland will be a new 500 kV transmission line connecting the Susquehanna, Lackawanna, Hopatcong, and Roseland buses. PPL is responsible for the first two legs. The Susquehanna-Lackawanna portion went into service on September 23, 2014, and the expectation, as of December 31, 2014, is that the Lackawanna–Hopatcong portion will be energized by June, 2015. The Hopatcong – Roseland leg, executed by PSE&G, was placed in service on April 1, 2014.[48]

The Surry Skiffes Creek 500kV was initiated in the fall of 2014 to relieve the overload of the James River Crossing Double Circuit Towerline anticipated to result from the retirement of Chesapeake units 1-4, which occurred in December 2014, and Yorktown 1, which is pending. It will include a new 7.7 mile 500kV line between Surry and Skiffes, a new 20.25 mile 230kV line between Skiffes Creek and Whealton, and a new Skiffes Creek 500/230kV switching station. Dominion anticipates beginning construction in early 2015 and expects the 500kV line to be completed by January 1, 2016 and the 230kV line to be completed by April 30, 2016.[49]

Transmission Facility Outages

Scheduling Transmission Facility Outage Requests

PJM designates some transmission facilities as reportable. A transmission facility is reportable if a change in its status can affect a transmission constraint on any Monitored Transmission Facility. A facility is also reportable if it impedes the free-flowing ties within the PJM RTO and/or adjacent areas.[50] When one of the reportable transmission facilities needs to be taken out of service, the TO is required to submit an outage request as early as possible. The outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days and greater than five calendar days; or less than or equal to five calendar days. Table 12-17 shows the summary of transmission facility outage requests by duration.

Table 12-17 Transmission facility outage request duration: 2013 and 2014

	2013		2014	
Days	Number of Outage Requests	Percent	Number of Outage Requests	Percent
<=5	5,467	78.8%	6,135	77.2%
>5 & <=30	1,099	15.8%	1,298	16.3%
>30	375	5.4%	512	6.4%
Total	6,941	100.0%	7,945	100.0%

After receiving a transmission facility outage request from a TO, PJM assigns a "received status," based on its submission date, outage date, and outage duration. The received status can be on time, late or past deadline, as defined in Table 12-18.[51]

46 See Dominion "Mt. Storm-Doubs," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/mount-storm-doubs.aspx>

47 See "Jacks Mountain," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/jacks-mountain.aspx>.

48 See "Susquehanna-Roseland," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/ susquehanna-roseland.aspx>.

49 See "Surry-Skiffes Creek 500kV and Skiffes Creek-Whealton 230kV Projects,"which can be accessed at: <https://www.dom.com/corporate/what-we-do/electricity/transmission-lines-and-projects/surry-skiffes-creek-500kv-and-skiffes-creek-whealton-230kv-projects>.

50 See PJM. "Manual 3a: Energy Management System (EMS) Model Updates and Quality Assurance (QA), Revision 9 (January 22, 2015).

51 See "PJM. "Manual 3: Transmission Operations," Revision 46 (December 1, 2014), p.58.

Table 12-18 PJM transmission facility request status definition

Duration	Request Submitted Date	Ticket Status
>30 days	The earlier of 1) February 1st , 2) the 1st of the month six months prior to the starting month of the outage	On Time
	After or on the earlier of 1) February 1st, 2) the 1st of the month six months prior to the starting month of the outage	Late
	After 8:00AM three days prior to the outage	Past Deadline
<=30 days and > 5 days	Before the 1st of the month six months prior to the starting month of the outage	On Time
	After or on the 1st of the month six months prior to the starting month of the outage	Late
	After 8:00AM three days prior to the outage	Past Deadline
<=5 days	Before the 1st of the month one month prior to the starting month of the outage	On Time
	After or on the 1st of the month one month prior to the starting month of the outage	Late
	After 8:00AM three days prior to the outage	Past Deadline

Table 12-19 shows a summary of requests with on time received status. In 2014, 52.7 percent of outage requests received were on time, compared to 49.5 percent in 2013.

Once received, PJM schedules the request according to its priority, which is determined by its submission date. If a request has an emergency flag set, it has the highest priority and will be approved even if submitted past its deadline. Table 12-20 shows emergency request statistics. Overall, 15.1 percent of all outage requests submitted in 2014 were for emergency outages.

For late tickets, the outage request may be denied or cancelled if it is expected to cause congestion. Table 12-21 shows a summary of requests which PJM determined might cause congestion. Overall, 23.7 percent of all tickets submitted in 2014 were congestion tickets, compared to 23.5 percent in 2013.

Table 12-19 Transmission outage requests with on time status: 2013 and 2014

	2013			2014		
Days	Number of Outage Requests	Number of On Time Outage Requests	Percent of On Time Outage Requests	Number of Outage Requests	Number of On Time Outage Requests	Percent of On Time Outage Requests
<=5	5,467	2,745	50.2%	6,135	3,271	53.3%
>5 & <=30	1,099	541	49.2%	1,298	688	53.0%
>30	375	150	40.0%	512	229	44.7%
Total	6,941	3,436	49.5%	7,945	4,188	52.7%

Table 12-20 Emergency transmission outage summary: 2013 and 2014

	2013			2014		
Days	Number of Outage Requests	Number of On Time Outage Requests	Percent of On Time Outage Requests	Number of Outage Requests	Number of On Time Outage Requests	Percent of On Time Outage Requests
<=5	5,467	2,745	50.2%	6,135	3,271	53.3%
>5 & <=30	1,099	541	49.2%	1,298	688	53.0%
>30	375	150	40.0%	512	229	44.7%
Total	6,941	3,436	49.5%	7,945	4,188	52.7%

Table 12-21 Transmission facility outage ticket congestion status summary: 2013 and 2014

	2013			2014		
Submission Status	Number of Tickets	Number of Congestion Tickets	Percent of Congestion Tickets	Number of Tickets	Number of Congestion Tickets	Percent of Congestion Tickets
Late & Emergency	1,008	109	10.8%	1,190	93	7.8%
Late & Non-Emergency	2,497	340	13.6%	2,567	366	14.3%
On Time & Emergency	10	6	60.0%	7	1	14.3%
On Time & Non-Emergency	3,426	1,179	34.4%	4,181	1,419	33.9%
Total	6,941	1,634	23.5%	7,945	1,879	23.7%

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage (Table 12-22). In 2014, 10.2 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 14.2 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs.

An outage lasting five days or less, with an on-time status, can be rescheduled within the original scheduled month without losing its on-time status.[52] This rule allows a TO to move an outage to an earlier date than originally requested within the same month with very short notice. The short notice may create issues for PJM market participants if it affects market outcomes. The MMU recommends that PJM reevaluate all transmission outage tickets with outages lasting five days or less when the outage is rescheduled.

A transmission outage ticket with outage duration exceeding five days can retain its on-time status if the outage is moved to a future month, and the revision is submitted by the first of the month prior to the month in which new proposed outage will occur.[53] This rule creates the opportunity for TOs to submit a transmission outage that, once approved, acts as a reservation that does not require further review and allows postponements without review.

The MMU recommends that PJM reevaluate all transmission outage tickets with outages lasting more than five days when the outage is rescheduled.

Table 12-22 Rescheduled transmission outage request summary: 2013 and 2014

	2013					2014				
Duration	Number of Tickets	Number of Approved and Revised Tickets	Percent of Approved and Revised Tickets	Number of Approved and Cancelled Tickets	Percent of Approved and Cancelled Tickets	Number of Tickets	Number of Approved and Revised Tickets	Percent of Approved and Revised Tickets	Number of Approved and Cancelled Tickets	Percent of Approved and Cancelled Tickets
<=5 days	5,467	1,020	18.7%	801	14.7%	6,135	607	9.9%	972	15.8%
>5 & <=30 days	1,099	254	23.1%	117	10.6%	1,298	139	10.7%	115	8.9%
>30 days	375	82	21.9%	25	6.7%	512	63	12.3%	41	8.0%
Total	6,941	1,356	19.5%	943	13.6%	7,945	809	10.2%	1,128	14.2%

52 PJM. "Manual 3: Transmission Outages," Revision 46 (December 1, 2014), p. 63.

53 PJM. "Manual 3: Transmission Outages," Revision: 46 (December 1, 2014), p. 64.