Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** As of September 30, 2014, 60,573.8 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 199,531.9 MW as of September 30, 2014. Of the capacity in queues, 6,617.64 MW, or 10.9 percent, are uprates and the rest are new generation. Wind projects account for 15,549.3 MW of nameplate capacity or 25.7 percent of the capacity in the queues. Combined-cycle projects account for 37,797.2 MW of capacity or 62.4 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-6, 26,342.1 MW are, or are planned to be, retired between 2011 and 2019, with all but 2,050.5 MW planned to be retired by the end of 2015. The AEP Zone accounts for 6,024.0 MW, or 22.9 percent, of all MW planned for retirement from 2014 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 282.5 MW of coal fired steam capacity are currently in the queue, 10,475.8 MW of coal fired steam capacity are slated for deactivation. Most of these retirements, 9,147 MW, are scheduled to take place by June 1, 2015, in large part due to the EPA's Mercury and Air Toxics Standards (MATS) set to go into effect at that time. In contrast, 39,287.9 MW of gas fired capacity are in the queue, while only 1,793.0 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 in completing 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 its parent company. 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.

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.

1 OATT Parts IV & VI.

PJM received 26 individual proposals from seven entities, including proposals from the incumbent transmission owner, PSE&G, and from non-incumbents. After the results of the initial selection process prompted a significant amount of feedback from market participants, PJM deferred the selection of a winner. In response to the feedback, PJM allowed the developers for five of the proposals to submit updated cost estimates, which they have done.

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.

Recommendations

The MMU recommends additional improvements to the planning process.

- There is no mechanism to permit a direct comparison, or 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. The MMU recommends the creation of such a mechanism. (Priority: Low. First reported 2013.)
- The MMU recommends that rules be implemented to permit competition to provide financing of 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.)
- 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.2 (Priority: Low. First reported 2013.)
- 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.)
- 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.)
- 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.)

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 mechanism to permit competition to build transmission projects or to obtain least cost financing through the capital markets.

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

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.

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 lag time 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 September 30, 2014, 60,573.8 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 199,531.9 MW as of September 30, 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 the first nine months of 2014, 2,515.0 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 (through September 30, 2014)	2,515.0

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 AA1 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.[3]

Table 12-2 shows MW in queues by expected completion date and MW changes in the queues between June 30, 2014 and September 30, 2014 for ongoing projects, i.e. projects with the status active, under construction or suspended.[4] Projects that are already in service are not included here. The total MW in queues decreased by 2,435.7 MW, or 3.9 percent, from 63,009.4 MW at the end of the first quarter of 2014. The change was the result of 3,317.4 MW in new projects entering the queue, 4,234.0 MW in existing projects withdrawing, and 1,487.0 MW going into service. The remaining difference is the result of projects adjusting their expected MW.

Table 12-2 Queue comparison by expected completion year (MW): June 30, 2014 vs. September 30, 2014[5]

	As of 6/30/2014	As of 9/30/2014	Quarterly Change (MW)	Quarterly Change (percent)
≤ 2013	0.0	0.0	0.0	NA
2014	14,313.9	5,321.4	(8,992.5)	(62.8%)
2015	11,741.8	13,098.3	1,356.5	11.6%
2016	12,686.3	15,484.3	2,798.0	18.1%
2017	11,512.5	11,958.1	445.6	3.7%
2018	10,013.0	11,891.5	1,878.5	15.8%
2019	1,148.0	1,148.0	0.0	0.0%
2020	0.0	78.2	78.2	NA
2024	1,594.0	1,594.0	0.0	0.0%
Total	63,009.4	60,573.8	(2,435.7)	(3.9%)

Table 12-3 shows the yearly project status changes in more detail and how scheduled queue capacity has changed between June 30, 2014 and September 30, 2014. For example, 3,317.4 MW entered the queue in the third quarter, 324.8 MW of which were withdrawn before the quarter ended. Of the total 39,458.9 MW marked as active at the beginning of this quarter, 3,276.2 MW were withdrawn, 295.4 MW were suspended, and 2,125.8 MW started construction by the end of the third quarter. The "In Service" column shows that 1,487.0 MW went into service in the third quarter of 2014, in addition to the 36,566.4 MW of capacity that already had the status "in service" at the beginning of the second quarter.

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

		Status at 9/30/2014				
Status at 6/30/2013	Total at 6/30/2014	Active	Suspended	Under Construction	In Service	Withdrawn
(Entered in Q2 2014)		2,992.7	0.0	0.0	0.0	324.8
Active	39,458.9	33,729.4	295.4	2,125.8	0.0	3,276.2
Suspended	4,602.8	0.0	4,022.8	20.0	0.0	560.0
Under Construction	18,947.7	0.0	183.6	17,204.1	1,487.0	73.0
In Service	36,566.4	0.0	0.0	0.0	36,566.4	0.0
Withdrawn	265,030.9	0.0	0.0	0.0	0.0	265,030.9
Total at 9/30/2014		36,722.1	4,501.8	19,349.9	38,053.4	269,264.9

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 September 30, 2014, there are 60,573.8 MW of capacity in queues that are not yet in service, of which 7.4 percent is suspended and 31.9 percent is under construction. The remaining 60.6 percent, or 36,722.1 MW, have not yet begun construction.

3 See "PJM Manual 14C: Generation and Transmission Interconnection Process," Section 3.7, <http://www.pjm.com/~/media/documents/manuals/m14c.ashx>.
4 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.
5 Wind and solar capacity in Table 12-2 through Table 12-5 have not been adjusted to reflect derating.

Table 12-4 Capacity in PJM queues (MW): At September 30, 2014 [6]

Queue	Active	In-Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	8,103.0	0.0	0.0	17,252.0	25,355.0
B Expired 31-Jan-99	0.0	4,645.5	0.0	0.0	14,956.7	19,602.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,470.3	4,001.3
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,182.0	8,032.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	8,021.8	8,817.0
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	1,115.6	0.0	0.0	17,933.8	19,049.4
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	3,728.4	3,831.4
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	451.2	669.2
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	3,555.6	4,210.4
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	126.0	1,386.4	1,968.3	0.0	19,274.6	22,755.3
S Expired 31-Jul-07	175.0	3,301.3	469.3	490.0	12,156.5	16,592.0
T Expired 31-Jan-08	2,045.0	1,325.0	1,885.0	128.0	22,173.3	27,556.3
U Expired 31-Jan-09	1,565.0	665.3	692.0	459.9	29,974.6	33,356.8
V Expired 31-Jan-10	2,022.4	1,812.8	1,237.6	148.0	11,780.1	17,000.9
W Expired 31-Jan-11	2,927.9	609.3	1,819.5	1,932.5	16,924.9	24,214.1
X Expired 31-Jan-12	5,972.8	302.0	6,839.5	328.8	16,919.1	30,362.2
Y Expired 30-Apr-13	7,120.1	187.8	2,283.8	592.6	15,789.3	25,973.4
Z Expired 30-Apr-14	11,643.8	55.9	85.5	0.0	2,967.8	14,753.1
AA through 30-Sep-14	3,019.1	0.0	0.0	0.0	4.5	3,023.6
Total	36,722.1	38,053.4	19,349.9	4,501.8	269,264.9	367,892.1

6 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 September 30, 2014, by unit type, control zone and LDA.[7] As of September 30, 2014, 60,573.8 MW of capacity were in generation request queues for construction through 2024, compared to 63,009.4 MW at June 30, 2014.[8] Table 12-5 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 282.5 MW of coal fired steam capacity are currently in the queue, 10,475.8 MW of coal fired steam capacity are slated for deactivation. Most of these retirements, 9,147 MW, are scheduled to take place by June 1, 2015, in large part due to the EPA's Mercury and Air Toxics Standards (MATS) set to go into effect at that time. In contrast, 39,287.9 MW of gas fired capacity are in the queue while only 1,793.0 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.

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

8 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 15,549.3 MW of wind resources and 1,811.0 MW of solar resources, the 60,573.8 MW currently active in the queue would be reduced to 45,923.1 MW.

Table 12-5 Queue capacity by control zone and LDA (MW) at September 30, 2014

LDA	Zone	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total Queue Capacity	Planned Retirements
EMAAC	AECO	1,034.0	137.3	7.5	0.0	0.0	89.5	0.0	0.0	373.0	1,641.3	500.2
	DPL	1,303.2	7.0	0.0	0.0	0.0	345.7	0.0	0.0	279.0	1,934.9	288.0
	JCPL	1,445.0	0.0	0.0	0.0	0.0	718.2	32.0	0.0	0.0	2,195.2	1,095.3
	PECO	980.5	10.0	3.7	0.0	330.0	0.0	0.0	0.0	0.0	1,324.2	1,104.7
	PSEG	3,187.9	286.0	8.0	0.0	0.0	176.6	1.0	3.0	0.0	3,662.5	2,737.4
	EMAAC Total	7,950.6	440.3	19.2	0.0	330.0	1,330.0	33.0	3.0	652.0	10,758.1	5,725.6
SWMAAC	BGE	0.0	256.0	29.0	0.4	0.0	22.0	0.0	132.0	0.0	439.4	189.0
	Pepco	2,643.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,643.6	2,474.0
	SWMAAC Total	2,643.6	256.0	29.0	0.4	0.0	22.0	0.0	132.0	0.0	3,083.0	2,663.0
WMAAC	Met-Ed	891.5	6.0	0.0	0.0	35.0	3.0	0.0	401.0	0.0	1,336.5	652.0
	PENELEC	879.0	121.4	61.8	45.3	0.0	31.8	29.5	0.0	483.3	1,652.0	634.0
	PPL	5,162.0	0.0	5.0	0.0	0.0	19.0	60.0	16.0	778.5	6,040.5	371.0
	WMAAC Total	6,932.5	127.4	66.8	45.3	35.0	53.8	89.5	417.0	1,261.8	9,029.0	1,657.0
Non-MAAC	AE	452.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	452.0	0.0
	AEP	6,501.0	46.0	20.4	7.0	102.0	110.4	36.0	326.5	7,487.8	14,637.1	6,024.0
	APS	3,091.4	25.7	99.6	63.5	0.0	39.9	0.0	49.2	615.0	3,984.2	3,028.0
	ATSI	2,795.0	0.4	1.7	0.0	0.0	0.0	6.0	135.0	617.0	3,555.1	2,266.0
	ComEd	1,625.0	193.3	15.3	22.7	0.0	15.0	60.6	0.0	3,354.0	5,285.9	1,624.0
	DAY	30.0	0.0	1.9	112.0	0.0	23.4	0.0	32.5	300.0	499.8	540.7
	DEOK	540.0	0.0	0.0	0.0	0.0	0.0	16.0	50.0	0.0	606.0	1,071.9
	DLCO	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.0	614.0
	Dominion	4,896.1	62.0	11.0	0.0	1,594.0	170.9	32.0	62.5	1,113.9	7,942.4	932.9
	EKPC	0.0	207.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	207.8	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
	PotomacEdison	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	69.6	69.6	0.0
	Vepco	0.0	0.0	0.0	0.0	0.0	45.6	0.0	0.0	78.2	123.8	0.0
	Non-MAAC Total	20,270.5	535.2	149.9	205.2	1,696.0	405.2	150.6	655.7	13,635.5	37,703.7	16,296.5
Total		37,797.2	1,358.9	264.9	250.8	2,061.0	1,811.0	273.1	1,207.7	15,549.3	60,573.8	26,342.1

Planned Retirements

As shown in Table 12-6, 26,342.1 MW is planned to be retired between 2011 and 2019, with all but 2,050.5 MW retired by the end of 2015. The AEP Zone accounts for 6,024.0 MW, or 22.9 percent, of all MW planned for deactivation from 2014 through 2019. 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, totaling 13,862.4 MW.

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	1,526.0
Planned Retirements 2014	1,739.9
Planned Retirements 2015	10,072.0
Planned Retirements Post-2015	2,050.5
Total	26,342.1

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

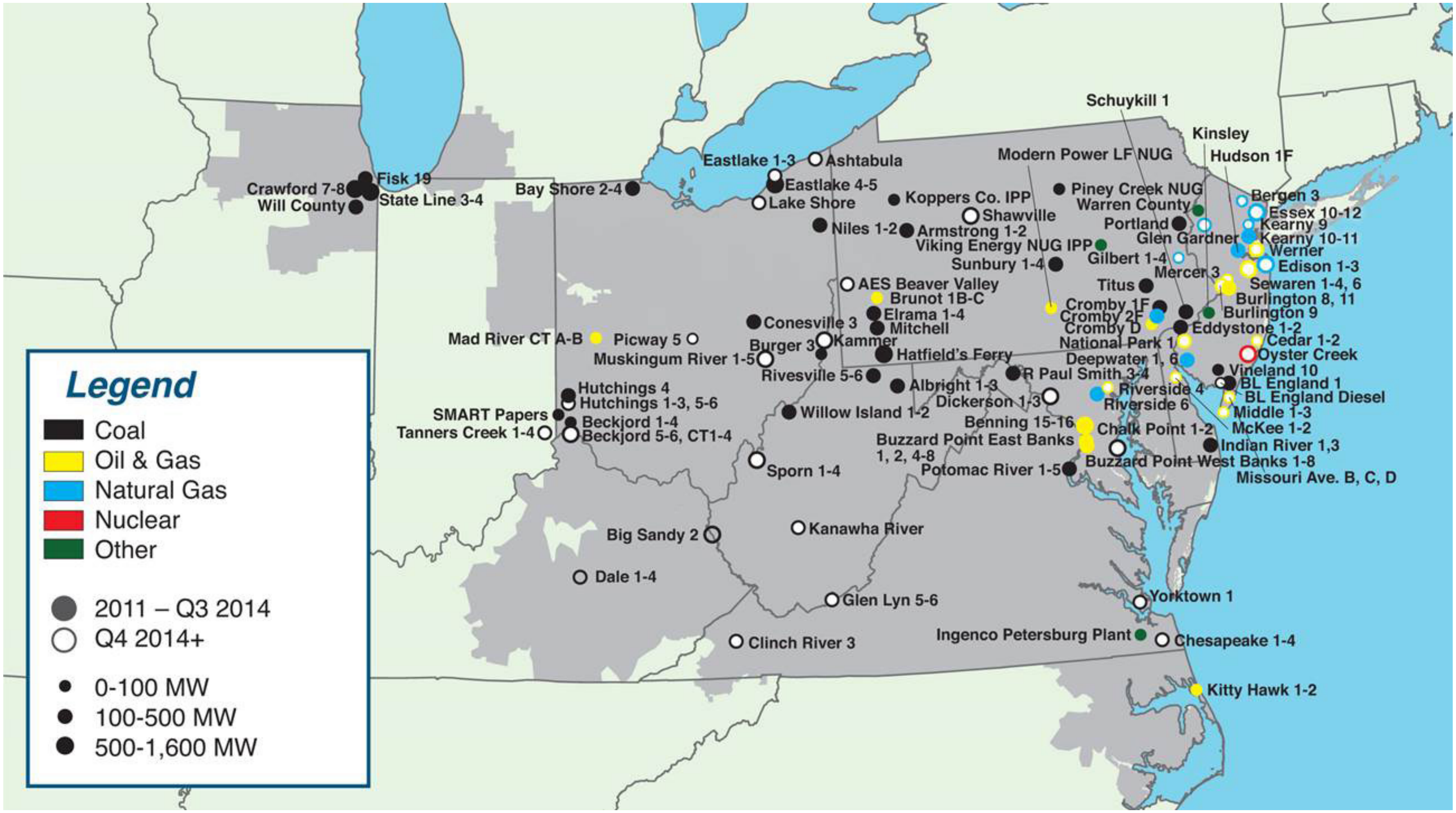

Table 12-7 Planned deactivations of PJM units, as of September 30, 2014

Unit	Zone	MW	Fuel	Unit Type	Projected Deactivation Date
Walter C Beckjord 5-6	DEOK	652.0	Coal	Steam	26-Nov-14
Walter C Beckjord GT1-4	DEOK	188.0	Coal	Steam	25-Dec-14
Chesapeake 1-4	Dominion	576.0	Coal	Steam	31-Dec-14
Kinsley Landfill	PSEG	0.9	Diesel	Diesel	31-Dec-14
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
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
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
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
Riverside 4	BGE	74.0	Natural gas	Steam	01-Jun-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
Oyster Creek	JCPL	614.5	Nuclear	Steam	31-Dec-19
Total		13,862.4			

Table 12-8 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2019. The majority, 77.8 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	123	166.6	56.4	20,496.6	77.8%
Diesel	6	12.5	38.3	74.9	0.3%
Heavy Oil	4	68.5	57.5	274.0	1.0%
Kerosene	20	41.4	45.5	828.2	3.1%
LFG	2	5.9	18.0	11.7	0.0%
Light Oil	15	76.6	43.8	1,148.7	4.4%
Natural Gas	49	57.9	46.8	2,838.5	10.8%
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	223	118.1	51.1	26,342.1	100.0%

Actual Generation Deactivations in 2014

Table 12-9 shows unit deactivations for the first nine months of 2014.[9] A total of 1,526.0 MW were retired during this period.

Table 12-9 Unit deactivations between January 1, 2014 and September 30, 2014

Company	Unit Name	ICAP	Primary Fuel	Zone Name	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	Diesel	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
Total		1,526.0				

9 See PJM. "*PJM Generator Deactivations,*" <http://pjm.com/planning/generation-retirements/gr-summaries.aspx> (Accessed April 05, 2014).

Generation Mix

Currently, PJM has an installed capacity of 199,531.9 MW (Table 12-10) including non-derated solar and wind resources, as well as energy-only units.

Table 12-10 Existing PJM capacity: at September 30, 2014 (By zone and unit type (MW)) [10]

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	63.1	0.0	1,071.9	2,071.0	0.0	24,264.8	0.0	1,753.2	37,806.2
APS	1,129.0	1,214.9	47.9	0.0	86.0	0.0	36.1	5,409.0	27.4	998.5	8,948.8
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	0.0	5,417.1	4.5	2,431.9	27,941.3
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	3,782.0	0.0	0.0	4,671.2
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	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
DPL	4,029.6	3,874.8	153.8	0.0	3,589.3	3,581.3	2.7	8,403.0	0.0	0.0	23,634.5
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	5,483.5	0.0	0.0	7,534.0
JCPL	1,692.5	1,233.1	16.1	0.0	400.0	614.5	59.8	10.0	0.0	0.0	4,026.0
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	29,008.8	31,421.8	812.2	30.0	8,378.0	33,744.6	271.6	89,428.3	94.9	6,341.7	199,531.9

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 199,531.9 MW. Units older than 45 years comprise 34,459.8 MW, or 17.3 percent of the total capacity.

Table 12-11 PJM capacity (MW) by age (years): at September 30, 2014

Age (years)	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 15	23,330.3	20,420.1	508.5	30.0	183.6	0.0	271.6	3,755.4	94.9	6,341.7	54,936.1
16 to 30	5,146.5	4,041.5	98.5	0.0	3,276.2	11,484.5	0.0	9,980.1	0.0	0.0	34,027.3
31 to 45	532.0	5,482.1	82.9	0.0	722.0	22,260.1	0.0	47,029.6	0.0	0.0	76,108.7
46 to 60	0.0	1,478.1	122.3	0.0	2,577.4	0.0	0.0	25,032.9	0.0	0.0	29,210.7
61 to 75	0.0	0.0	0.0	0.0	501.7	0.0	0.0	3,481.3	0.0	0.0	3,983.0
76 and over	0.0	0.0	0.0	0.0	1,117.1	0.0	0.0	149.0	0.0	0.0	1,266.1
Total	29,008.8	31,421.8	812.2	30.0	8,378.0	33,744.6	271.6	89,428.3	94.9	6,341.7	199,531.9

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

Figure 12-2 PJM capacity (MW) by age (years): at September 30, 2014

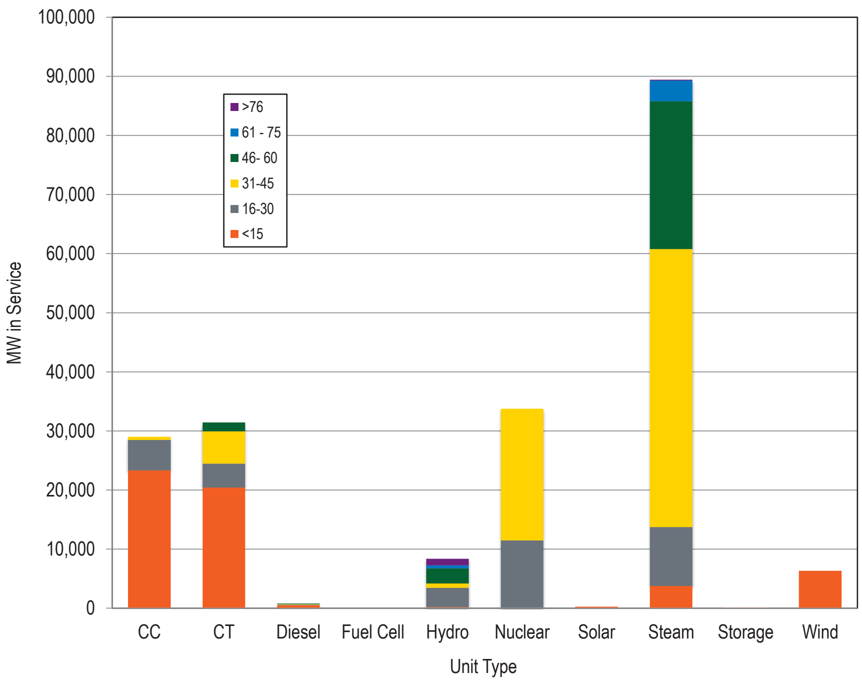

Table 12-12 shows the effect that the new generation in the queues would have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age as of September 30, 2014 retire by 2024. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generation. Existing capacity in SWMAAC is currently 63.7 percent steam; this would be reduced to 44.9 percent by 2024. CC and CT generators would comprise 40.4 percent of total capacity in SWMAAC in 2024.

In Non-MAAC zones, 82.0 percent of all generation 40 years or older, as of September 30, 2014, is steam, primarily coal.[11] If the older coal units retire and if all queued wind MW are built as planned, by 2024, wind farms would account for 11.7 percent of total non-derated ICAP MW in Non-MAAC zones.

Generation and Transmission Interconnection Planning Process

PJM continues to look for ways to improve the planning process, with the most recent set of changes effective in May 2012.[12] These changes include 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).[13] 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.[14]

11 Non-MAAC zones consist of the AEP, AP, ATSI, ComEd, DAY, DEOK, DLCO, and Dominion control zones.
12 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>. (Accessed December 4, 2013).
13 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).
14 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).

Table 12-12 Comparison of generators 40 years and older with slated capacity additions (MW) through 2024, as of September 30, 2014

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	1.9%	10,084.0	29.7%	7,950.6	0.0	18,034.6	43.6%
	Combustion Turbine	3,580.2	33.7%	7,249.2	21.4%	440.3	2,196.2	5,493.3	13.3%
	Diesel	58.9	0.6%	149.7	0.4%	19.2	8.9	160.0	0.4%
	Fuel Cell	0.0	0.0%	30.0	0.1%	0.0	0.0	30.0	0.1%
	Hydroelectric	2,042.0	19.2%	2,047.0	6.0%	0.0	0.0	2,047.0	4.9%
	Nuclear	1,739.9	16.4%	8,654.3	25.5%	330.0	0.0	8,984.3	21.7%
	Solar	0.0	0.0%	216.7	0.6%	1,330.0	0.0	1,546.7	3.7%
	Steam	2,995.0	28.2%	5,475.1	16.1%	3.0	1,101.5	4,376.6	10.6%
	Storage	0.0	0.0%	3.0	0.0%	33.0	0.0	36.0	0.1%
	Wind	0.0	0.0%	7.5	0.0%	652.0	0.0	659.5	1.6%
	EMAAC Total	10,614.0	100.0%	33,916.5	100.0%	10,758.1	3,306.6	41,368.0	100.0%
SWMAAC	Combined Cycle	0.0	0.0%	230.0	2.2%	2,643.6	0.0	2,873.6	23.5%
	Combustion Turbine	849.3	17.2%	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	0.0	0.0%	1,716.0	16.5%	0.0	0.0	1,716.0	14.0%
	Solar	0.0	0.0%	0.0	0.0%	22.0	0.0	22.0	0.2%
	Steam	4,098.5	82.8%	6,644.6	63.7%	132.0	1,278.0	5,498.6	44.9%
	SWMAAC Total	4,947.8	100.0%	10,430.6	100.0%	3,083.0	1,278.0	12,235.6	100.0%
WMAAC	Combined Cycle	0.0	0.0%	3,918.9	16.7%	6,932.5	0.0	10,851.4	34.1%
	Combustion Turbine	713.5	7.2%	1,430.2	6.1%	127.4	0.0	1,557.6	4.9%
	Diesel	46.2	0.5%	147.7	0.6%	66.8	6.0	208.5	0.7%
	Hydroelectric	887.2	9.0%	1,238.4	5.3%	45.3	0.0	1,283.7	4.0%
	Nuclear	0.0	0.0%	3,325.0	14.2%	35.0	0.0	3,360.0	10.6%
	Solar	0.0	0.0%	15.0	0.1%	53.8	0.0	68.8	0.2%
	Steam	8,225.5	83.3%	12,163.4	52.0%	417.0	597.0	11,983.4	37.6%
	Storage	0.0	0.0%	20.0	0.1%	89.5	0.0	109.5	0.3%
	Wind	0.0	0.0%	1,150.6	4.9%	1,261.8	0.0	2,412.4	7.6%
	WMAAC Total	9,872.4	100.0%	23,409.2	100.0%	9,029.0	603.0	31,835.1	100.0%
Non-MAAC	Combined Cycle	0.0	0.0%	14,775.9	11.2%	20,270.5	0.0	35,046.4	21.8%
	Combustion Turbine	1,250.6	2.7%	20,930.7	15.9%	535.2	0.0	21,465.9	13.3%
	Diesel	71.8	0.2%	486.5	0.4%	149.9	0.0	636.4	0.4%
	Hydroelectric	1,702.0	3.7%	5,092.6	3.9%	205.2	0.0	5,297.8	3.3%
	Nuclear	5,295.9	11.4%	20,049.3	15.2%	1,696.0	0.0	21,745.3	13.5%
	Solar	0.0	0.0%	40.0	0.0%	405.2	0.0	445.2	0.3%
	Steam	37,968.7	82.0%	65,145.2	49.4%	655.7	8,674.8	57,126.1	35.5%
	Storage	0.0	0.0%	71.9	0.1%	150.6	0.0	222.5	0.1%
	Wind	0.0	0.0%	5,183.6	3.9%	13,635.5	0.0	18,819.1	11.7%
	Non-MAAC Total	46,289.0	100.0%	131,775.7	100.0%	37,703.7	8,674.8	160,804.6	100.0%
All Areas	Total	71,723.2		199,531.9		60,573.8	13,862.4	246,243.3	

FERC Order No. 792 was issued on November 22, 2013, to make several amendments to the SGIP and SGIA.[15] 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.[16] 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.[17] 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.[18] PJM filed these revisions to the OATT with FERC on August 4, 2014.[19] 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, or retooled, when a project is withdrawn because it may affect the investments of 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 (ICSA). It further states that a feasibility study should take no longer than 334 days from the day it entered the queue.[20] 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.[21] PJM currently uses a value of 53 percent for commercial probability.[22]

Table 12-14 shows the milestone due when projects were withdrawn, for all withdrawn projects. Consistent with PJM's estimate, 48.6 percent of projects withdrawn were withdrawn before the Impact Study was completed.

Table 12-14 Milestone due at time of withdrawal

Milestone Due	Projects Withdrawn	Percent
Feasibility	138	9.2%
Impact	592	39.4%
Facility	355	23.6%
Interconnection/Construction Service Agreement (ISA/CSA)	217	14.4%
Under Construction	202	13.4%
Total	1,504	100.0%

Table 12-13 PJM generation planning process

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

15 See *Small Generator Interconnection Agreements and Procedures*, 145 FERC ¶ 61,159 (2013 (Order No. 792).
16 See Order No. 792 at P 106.
17 See *Id.* at P 106.
18 See Order No. 792 at P 228.
19 See PJM Compliance Filing, FERC Docket No. ER14-2590-000 (August 4, 2014).
20 See PJM. Manual 14A. "Generation and Transmission Interconnection Process," Revision 15 (April 17, 2014), p.37, <http://www.pjm.com/~/media/documents/manuals/m14a.ashx>.
21 See PJM. Manual 14B. "PJM Region Transmission Planning Process," Revision 27 (April 23, 2014), p.82, <http://www.pjm.com/~/media/documents/manuals/m14b.ashx>.
22 See PJM Planning Committee meeting presentation 'Commercial Probability, "October 10, 2013, <http://www.pjm.com/~/media/committees-groups/committees/pc/20131010/20131010-item-09-commercial-probability.ashx>.

Table 12-15 and Table 12-16 show the time spent at various stages in the queue process, as well as the completion time for the studies performed. For completed projects, there is an average time of 3,076 days, or 8.4 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 660 days between entering a queue and withdrawing. It takes an average of 4.6 years to begin construction, with the worst case taking 17.5 years.

Table 12-15 Average project queue times (days) at September 30, 2014

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	1,182	783	154	3,799
In-Service	3,076	1,399	335	6,392
Suspended	1,807	659	607	3,619
Under Construction	1,663	852	335	6,380
Withdrawn	650	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. For the 506 projects in the queue as of September 30, 2014, 29 had reached as far as the milestone of feasibility study completion and 176 were under construction.

Table 12-16 PJM generation planning summary: at September 30, 2014

Milestone Completed	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Not Started	43	8.5%	105	366
Feasibility Study	29	5.7%	1,621	2,704
Impact Study	152	30.0%	1,046	3,068
Facility Study	31	6.1%	1,809	3,495
ISA/CSA	75	14.8%	313	790
Under Construction	176	34.8%	1,393	3,719
Total	506	100.0%		

Regional Transmission Expansion Plan (RTEP)

Artificial Island

PJM has been seeking technical 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 specified its transmission expansion project solicitation process in two Order No 1000 FERC Compliance filings (dated October 25, 2012 and July 22, 2013.)[23] PJM evaluated 26 proposals based on factors including siting, permitting, line crossings, outage requirements, and impacts to the Salem nuclear plant.

The Transmission Expansion Advisory Committee (TEAC) recommended that PSE&G be selected to proceed with the Artificial Island project.[24] [25] On July 23, 2014, the PJM Board of Managers deferred the selection of a winner in order to review and address issues raised.[26]

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.[27] All of the bidders responded by submitting the supplemental information requested.[28] 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.[29]

Other RTEP Proposals

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. The RTEP proposal window 1 was open from June 27, 2014 through July 28, 2014. During this window, 106 baseline reliability projects were proposed, encompassing 18 target transmission owner zones and 10 states. None of these submissions were by a developer that was not a transmission owner.

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

24 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.

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

26 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>.

27 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.

28 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.

29 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.

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 overall (all transmission owner upgrades) were recommended at the September 25, 2014, TEAC meeting and will be taken to the PJM Board for approval in November 2014.[30]

RTEP's window 2 is open now for additional reliability issues. In compliance with Order 1000, PJM is scheduled to open a proposal window on November 1, 2014, and close it on February 28, 2015, for all long term issues. For this window, PJM will accept proposals addressing not just long term reliability, but also energy market efficiency, capacity market efficiency, and public policy.[31]

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.

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 rebuild project is complete and was energized on June 3, 2014, one year ahead of schedule.[32] Dominion will complete its Right of Way Rehabilitation by the fall of 2014.

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. As of June 30, 2014, the project is experiencing order delays of necessary components. Anticipated milestone completion dates have not been adjusted. 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.[33]

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. Their expectations as of June 30, 2014, are for the Susquehanna-Lackawanna portion to be in service by December 2014 and the Lackawanna–Hopatcong portion by June, 2015. The remaining leg, Hopatcong – Roseland, is being executed by PSE&G and is anticipated to be in service by June 2015. Engineering and design of the transmission and substations are over 95 percent complete for both parties.[34]

The Surry Skiffes Creek 500kV project is new this quarter. It was initiated to relieve the overload of the James River Crossing Double Circuit Towerline anticipated to result from the retirement of Chesapeake units 1-4 and Yorktown 1, scheduled for December 2014. It will comprise 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 the fall of 2014 and expects the 500kV line to be completed by January 01, 2016 and the 230kV line to be completed by April 30, 2016.[35]

30 "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.
31 "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>.
32 See Dominion "*Mt. Storm-Doubs 500kV Rebuild Project*," <https://www.dom.com/about/electric-transmission/mtstorm/index.jsp> (March 31, 2014).
33 See "Jacks Mountain," <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/jacks-mountain.aspx>.
34 See "Susquehanna-Roseland," <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/ susquehanna-roseland.aspx>.
35 See "Surry Skiffes Creek," http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/surry-skiffes-creek.aspx.

Figure 12-3 PJM Backbone Projects