Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** As of March 31, 2015, 67,268.0 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 200,808.1 MW as of March 31, 2015. Of the capacity in queues, 8,703.1 MW, or 12.9 percent, are uprates and the rest are new generation. Wind projects account for 15,216.0 MW of nameplate capacity or 22.6 percent of the capacity in the queues. Combined-cycle projects account for 40,933.4 MW of capacity or 60.9 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-6, 26,787.8 MW have been, or are planned to be, retired between 2011 and 2019, with all but 2,924.8 MW planned to be retired by the end of 2015. The AEP Zone accounts for 6,024.0 MW, or 22.5 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, 9,343.8 MW of coal fired steam capacity are slated for deactivation. Most of these retirements, 7,692.8 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, 43,479.3 MW of gas fired capacity are in the queue, while only 1,572.0 MW of natural gas units are planned to retire. The replacement of coal 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,

1 PJM. OATT Parts IV & VI.

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 staff announced on April 28, 2015, that they will recommend that the Board approve the Artificial Island project being designated to LS Power, PSE&G, and PHI with a total cost estimate between $263M and $283M.

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

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>.

between incumbent transmission providers and nonincumbent providers. (Priority: Medium. First reported 2014. Status: Not adopted.)

- The MMU recommends that PJM reevaluate transmission outage tickets when the outage is rescheduled. (Priority: Low. First reported 2014. Status: Not adopted.)

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 March 31, 2015, 67,268.0 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 200,808.1 MW as of March 31, 2015. 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 three months of 2015, 858.8 MW of nameplate capacity were added in PJM.

Table 12-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through 2015

	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
2015	858.8

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 December 31, 2014 and March 31, 2015 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 decreased by 840.4 MW, or 1.2 percent, from 68,108.4 MW at the end of 2014. The change was the result of 2,582.8 MW in new projects entering the queue, 2,409.6 MW in existing projects withdrawing, and 873.5 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): December 31, 2014 vs. March 31, 2015[6]

			Quarterly Change	
Year	As of 12 /31/2014	As of 3 /31/2015	MW	Percent
2015	13,992.5	15,609.4	1,616.9	11.6%
2016	16,974.2	17,453.7	479.5	2.7%
2017	14,075.1	12,878.1	(1,197.0)	(9.3%)
2018	12,587.0	14,139.0	1,552.0	11.0%
2019	3,051.0	4,191.8	1,140.8	27.2%
2020	1,152.0	1,152.0	0.0	0.0%
2021	78.2	250.0	171.8	68.7%
2024	1,594.0	1,594.0	0.0	0.0%
Total	68,108.4	67,268.0	(840.4)	(1.2%)

Table 12-3 shows the yearly project status changes in more detail and how scheduled queue capacity has changed between December 31, 2014 and March 31, 2015. For example, 2,582.8 MW entered the queue in the first quarter of 2015, 404.6 MW of which were withdrawn before the quarter ended. Of the total 41,729.0 MW marked as active at the beginning of the year, 1,997.7 MW were withdrawn, 894.0 MW were suspended, 1,290.4 MW started

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

construction, and 14.9 MW went into service by the end of the first quarter. The Under Construction column shows that 1,879.7 MW began construction in the first three months of 2015, in addition to the 20,188.8 MW of capacity that maintained the status under construction from the previous quarter.

Table 12-3 Change in project status (MW): December 31, 2014 vs. March 31, 2015

		Status at 3/31/2015				
Status at 12/31/2014	Total at 12/31/2014	Active	Suspended	Under Construction	In Service	Withdrawn
(Entered in Q1 2015)		2,582.8	0.0	0.0	0.0	404.6
Active	**41,729.0**	37,392.0	894.0	1,290.4	14.9	1,997.7
Suspended	**4,751.8**	0.0	3,988.5	589.3	0.0	174.0
Under Construction	**21,627.6**	0.0	342.3	20,188.8	858.6	237.9
In Service	**38,341.7**	0.0	0.0	0.0	38,101.7	0.0
Withdrawn	**274,630.6**	0.0	0.0	0.0	0.0	274,630.6
Total at 3/31/2015		39,974.8	5,224.8	22,068.4	38,975.3	277,444.8

Table 12-4 shows the amount of capacity active, in-service, under construction, suspended, or withdrawn for each queue since the beginning of the 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 March 31, 2015, there are 67,268.0 MW of capacity in queues that are not yet in service, of which 7.8 percent is suspended and 32.8 percent is under construction. The remaining 59.4 percent, or 39,974.8 MW, have not yet begun construction.

Table 12-4 Capacity in PJM queues (MW): At March 31, 2015[7]

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	4,477.5	0.0	0.0	14,956.7	19,434.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,470.7	4,001.7
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	1,189.6	0.0	0.0	17,962.3	19,151.9
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	2,425.4	2,643.4
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	1,448.2	437.0	0.0	5,466.8	7,352.0
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	1,986.4	1,068.3	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	675.0	1,310.0	2,764.8	300.0	22,488.3	27,538.1
U Expired 31-Jan-09	1,430.0	925.3	481.9	400.0	30,119.6	33,356.8
V Expired 31-Jan-10	1,252.4	1,812.8	1,771.3	148.0	12,016.4	17,000.9
W Expired 31-Jan-11	2,023.0	867.4	2,059.4	1,446.5	17,918.6	24,314.9
X Expired 31-Jan-12	3,720.5	322.0	7,461.9	1,277.8	17,586.0	30,368.2
Y Expired 30-Apr-13	5,654.7	243.3	3,278.1	630.8	16,211.3	26,018.0
Z Expired 30-Apr-14	9,446.6	133.1	257.0	21.7	4,828.9	14,687.4
AA1 Expired 31-Oct-14	12,674.3	0.0	0.0	0.0	215.8	12,890.1
AA2 through 31-Dec-14	2,993.3	0.0	0.0	0.0	404.6	3,397.9
Total	39,974.8	38,975.3	22,068.4	5,224.8	277,444.8	383,688.1

7 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, by unit type, control zone, and locational deliverability areas (LDA).[8] As of March 31, 2015, 67,268.0 MW of capacity were in generation request queues for construction through 2024, compared to 68,108.4 MW at December 31, 2014.[9] 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.

Table 12-5 Queue capacity by control zone and LDA (MW) at March 31, 2015[10]

LDA	Zone	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total Queue Capacity	Planned Retirements
EMAAC	AECO	1,276.0	302.8	0.0	0.0	0.0	68.2	0.0	0.0	373.0	2,020.0	162.2
	DPL	1,210.2	17.0	0.0	0.0	0.0	463.3	0.0	0.0	279.0	1,969.5	34.0
	JCPL	2,535.0	0.0	0.0	0.0	0.0	595.1	0.0	108.0	0.0	3,238.1	1,084.5
	PECO	1,054.5	0.0	3.7	0.0	330.0	0.0	0.0	0.0	0.0	1,388.2	0.0
	PSEG	2,562.9	288.0	13.6	0.0	0.0	146.6	0.0	1.0	0.0	3,012.1	2,139.0
	EMAAC Total	8,638.6	607.8	17.3	0.0	330.0	1,273.3	0.0	109.0	652.0	11,628.0	3,419.7
SWMAAC	BGE	0.0	256.0	29.0	0.4	0.0	26.1	132.0	0.0	0.0	443.5	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	26.1	132.0	0.0	0.0	3,058.0	1,278.0
WMAAC	Met-Ed	800.0	91.5	0.0	0.0	16.8	3.0	401.0	0.0	0.0	1,312.3	0.0
	PENELEC	2,117.0	592.3	61.8	45.3	0.0	13.5	0.0	48.4	418.6	3,296.8	603.0
	PPL	5,317.0	0.0	5.0	0.0	0.0	129.0	16.0	40.0	679.0	6,186.0	0.0
	WMAAC Total	8,234.0	683.8	66.8	45.3	16.8	145.5	417.0	88.4	1,097.6	10,795.1	603.0
Non-MAAC	AEP	5,724.0	51.0	18.0	53.5	102.0	118.4	245.0	68.0	6,937.8	13,317.7	5,367.0
	APS	3,190.4	12.0	99.6	77.0	0.0	107.8	1,717.2	11.0	956.6	6,171.5	0.0
	ATSI	3,912.0	0.8	1.7	0.0	0.0	0.0	0.0	0.0	518.0	4,432.5	737.3
	ComEd	2,510.8	603.3	15.3	22.7	0.0	14.0	27.0	100.6	3,562.0	6,855.7	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	20.0	50.0	18.0	0.0	601.0	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	1,273.0	62.5	128.0	1,192.1	9,578.7	438.0
	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	21,446.3	729.1	147.5	265.2	1,696.0	1,556.6	2,134.2	345.6	13,466.5	41,786.9	7,547.1
Total		40,933.4	2,276.7	260.6	310.8	2,042.8	3,001.5	2,683.2	543.0	15,216.1	67,268.0	12,847.8

8 Unit types designated as reciprocating engines are classified here as diesel.
9 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 15,216.1 MW of wind resources and 3,001.5 MW of solar resources, the 67,268.0MW currently active in the queue would be reduced to 52,169.1 MW.
10 This data includes only projects with a status of active, under-construction, or suspended.

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, 9,337.8 MW of coal fired steam capacity are slated for deactivation. Most of these retirements, 7,686.8 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, 43,366.3 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, 26,781.8.8 MW is planned to be retired between 2011 and 2019, with all but 2,924.8 MW retired by the end of 2015. The AEP Zone accounts for the largest amount, 6,024.0 MW or 22.5 percent, of all MW planned for deactivation from 2015 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.

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

	Coal	Diesel	Heavy Oil	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Waste Coal	Wood Waste	Total
Retirements 2011	543.0	0.0	0.0	0.0	0.0	63.7	522.5	0.0	0.0	0.0	1,129.2
Retirements 2012	5,907.9	0.0	0.0	0.0	0.0	788.0	250.0	0.0	0.0	16.0	6,961.9
Retirements 2013	2,558.9	2.9	166.0	0.0	3.8	85.0	0.0	0.0	31.0	8.0	2,855.6
Retirements 2014	2,427.0	50.0	0.0	184.0	15.3	0.0	273.0	0.0	0.0	0.0	2,949.3
Retirements 2015	0.0	0.0	0.0	44.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0
Planned Retirements 2015	7,686.8	4.0	74.0	600.2	0.0	212.0	1,340.0	0.0	0.0	0.0	9,917.0
Planned Retirements Post-2015	1,651.0	14.3	34.0	0.0	0.0	0.0	611.0	614.5	0.0	0.0	2,924.8
Total	20,774.6	71.2	274.0	828.2	19.1	1,148.7	2,996.5	614.5	31.0	24.0	26,781.8

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

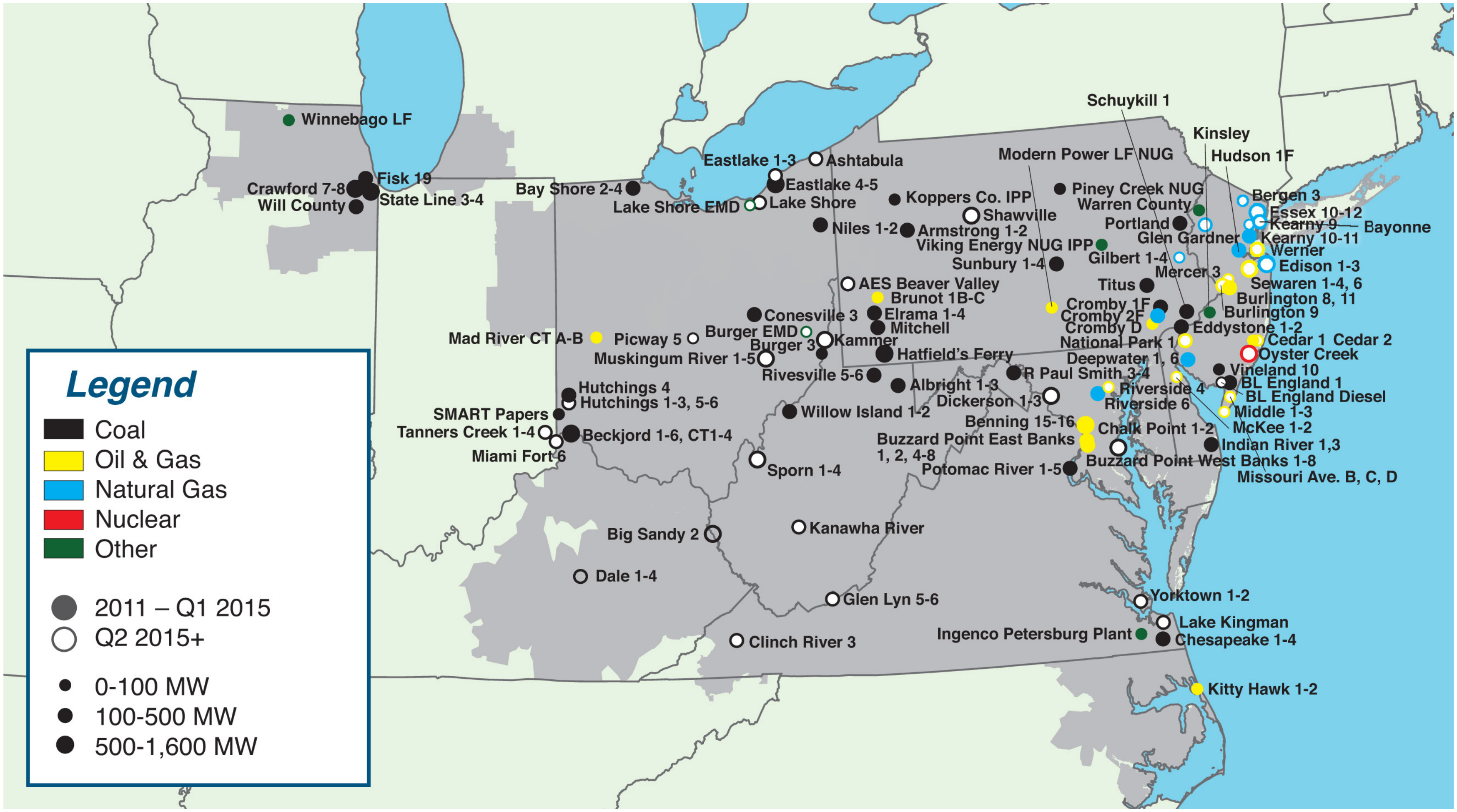


Table 12-7 Planned deactivations of PJM units, as of March 31, 2015

Unit	Zone	MW	Fuel	Unit Type	Projected Deactivation Date
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	597.0	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 2	AECO	21.6	Kerosene	Combustion Turbine	01-May-15
Middle 1-3	AECO	74.7	Kerosene	Combustion Turbine	01-May-15
Missouri Ave B, C, D	AECO	57.9	Kerosene	Combustion Turbine	01-May-15
Essex 12	PSEG	184.0	Natural gas	Combustion Turbine	31-May-15
Lake Kingman	Dominion	115.0	Coal	Steam	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 6	PSEG	105.0	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
Yorktown 1-2	Dominion	323.0	Coal	Steam	31-Mar-16
BL England Diesels	AECO	8.0	Diesel	Diesel	31-May-16
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
Sewaren 1-4	PSEG	453.0	Kerosene	Combustion Turbine	01-Nov-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	Nuclear	31-Dec-19
Total		12,841.8			

Table 12-8 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2019. The majority, 77.5 percent of all MW retiring during this period are coal steam units. These units have an average age of 56.2 years and an average size of 166.2 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	125	166.2	56.2	20,774.6	77.6%
Diesel	6	11.9	42.7	71.2	0.3%
Heavy Oil	4	68.5	57.3	274.0	1.0%
Kerosene	20	41.4	45.5	828.2	3.1%
Landfill Gas	4	4.8	14.8	19.1	0.1%
Light Oil	15	76.6	43.8	1,148.7	4.3%
Natural Gas	50	59.9	46.6	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	117.5	50.8	26,781.8	100.0%

Actual Generation Deactivations in 2015

Table 12-9 shows the units that were deactivated in 2015.

Table 12-9 Unit deactivations in 2015

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Average Age (Years)	Retirement Date
Calpine Corporation	Cedar 1	44.0	Kerosene	AECO	43	28-Jan-15
Total		44.0				

Generation Mix

As of March 31, 2015, PJM had an installed capacity of 200,808.1 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 March 31, 2015 (By zone and unit type (MW))[11]

Zone	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	901.9	661.9	22.6	0.0	0.0	0.0	41.7	815.9	0.0	7.5	2,451.5
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	2,854.1	7,244.0	93.8	0.0	0.0	10,473.5	9.0	5,417.1	4.5	2,431.9	28,527.9
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	654.0	0.0	0.0	0.0	0.0	0.0	3,730.0	2.0	0.0	4,433.2
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	7,827.0	0.0	0.0	24,522.5
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	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
PPL	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
PSEG	3,091.3	2,653.8	11.1	0.0	5.0	3,493.0	108.2	2,050.1	2.0	0.0	11,414.5
Total	31,056.8	31,189.8	818.9	30.0	8,378.0	33,744.6	317.1	88,570.3	100.9	6,601.7	200,808.1

Figure 12-2 and Table 12-11 show the age of PJM generators by unit type. Units older than 40 years comprise 78,534.2 MW, or 39.1 percent, of the total capacity of 200,808.1 MW.

Table 12-11 PJM capacity (MW) by age (years): at March 31, 2015

Age (years)	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 20	26,678.3	21,628.7	553.2	30.0	189.6	0.0	317.1	5,212.9	100.9	6,601.7	61,312.4
20 to 40	3,936.5	2,913.9	88.8	0.0	3,557.2	22,906.4	0.0	27,558.7	0.0	0.0	60,961.5
40 to 60	442.0	6,647.2	174.9	0.0	3,010.0	10,838.2	0.0	51,641.4	0.0	0.0	72,753.7
More than 60	0.0	0.0	2.0	0.0	1,621.2	0.0	0.0	4,157.3	0.0	0.0	5,780.5
Total	31,056.8	31,189.8	818.9	30.0	8,378.0	33,744.6	317.1	88,570.3	100.9	6,601.7	200,808.1

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

Figure 12-2 PJM capacity (MW) by age (years): at March 31, 2015

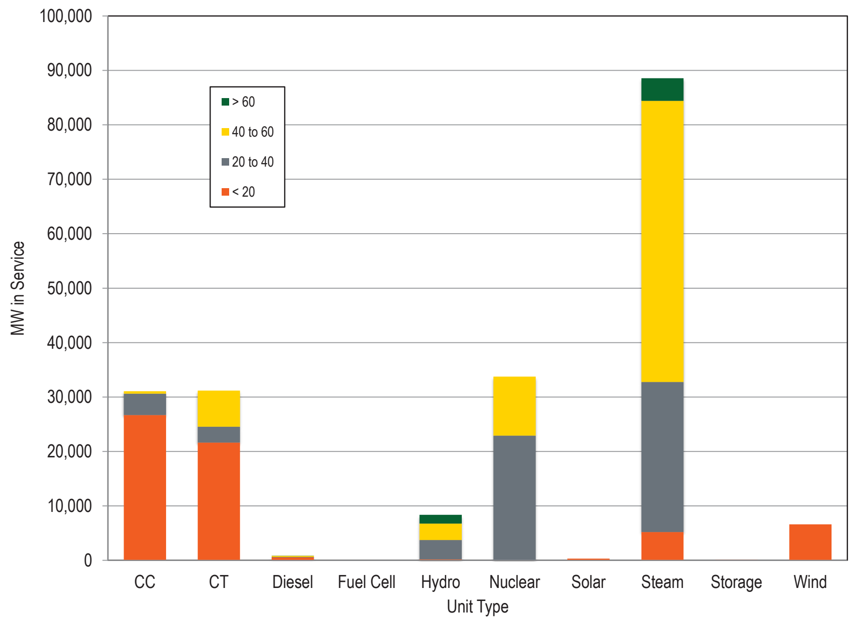


Table 12-12 shows the effect that expected retirements and new generation in the queues would have on the existing generation mix five years from now. Even though 78,534.2 MW, or 39.1 percent, of the total capacity is more than 40 years old, only 12,847.8 MW are planned to retire within the next five years. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generation. In SWMAAC, existing capacity is 63.7 percent steam, which will be reduced to 50.0 percent by 2020 as a result of the addition of 2,614.5 MW of planned CC capacity. The percentage of CC capacity would increase from 2.2 percent to 21.2 percent of total capacity in SWMAAC in 2020.

A similar shift in steam and CC capacity is expected elsewhere in PJM. In non-MAAC zones, there are 13,216.5 MW of wind capacity planned, which in conjunction with the shifts in steam and CC capacity, would result in wind accounting for 11.4 percent of total installed (non-derated) MW in non-MAAC zones.

Table 12-12 Expected capacity in five years, as of March 31, 2015[12]

Area	Unit Type	Current Generator Capacity	Percent of Area Total	Planned Additions	Planned Retirements	Estimated Capacity in 5 Years	Percent of Area Total
EMAAC	Combined Cycle	10,084.0	29.7%	8,638.6	0.0	18,722.6	44.5%
	Combustion Turbine	7,205.2	21.2%	607.8	2,152.2	5,660.8	13.4%
	Diesel	148.8	0.4%	17.3	8.0	158.1	0.4%
	Fuel Cell	30.0	0.1%	0.0	0.0	30.0	0.1%
	Hydroelectric	2,047.0	6.0%	0.0	0.0	2,047.0	4.9%
	Nuclear	8,654.3	25.5%	330.0	614.5	8,369.8	19.9%
	Solar	253.2	0.7%	1,273.3	0.0	1,526.4	3.6%
	Steam	5,475.1	16.1%	0.0	645.0	4,830.1	11.5%
	Storage	3.0	0.0%	109.0	0.0	112.0	0.3%
	Wind	7.5	0.0%	652.0	0.0	659.5	1.6%
	EMAAC Total	33,908.1	100.0%	11,628.0	3,419.7	42,116.3	100.0%
SWMAAC	Combined Cycle	230.0	2.2%	2,614.5	0.0	2,844.5	21.2%
	Combustion Turbine	1,811.7	17.4%	256.0	0.0	2,067.7	15.4%
	Diesel	28.3	0.3%	29.0	0.0	57.3	0.4%
	Hydroelectric	0.0	0.0%	0.4	0.0	0.4	0.0%
	Nuclear	1,716.0	16.5%	0.0	0.0	1,716.0	12.8%
	Solar	0.0	0.0%	26.1	0.0	26.1	0.2%
	Steam	6,644.6	63.7%	132.0	74.0	6,702.6	50.0%
	SWMAAC Total	10,430.6	100.0%	3,058.0	74.0	13,414.6	100.0%
WMAAC	Combined Cycle	3,918.9	16.7%	8,234.0	0.0	12,152.9	36.2%
	Combustion Turbine	1,430.2	6.1%	683.8	0.0	2,114.0	6.3%
	Diesel	147.7	0.6%	66.8	0.0	214.5	0.6%
	Hydroelectric	1,238.4	5.3%	45.3	0.0	1,283.7	3.8%
	Nuclear	3,325.0	14.2%	16.8	0.0	3,341.8	9.9%
	Solar	15.0	0.1%	145.5	0.0	160.5	0.5%
	Steam	12,163.4	52.0%	417.0	597.0	11,983.4	35.7%
	Storage	20.0	0.1%	88.4	0.0	108.4	0.3%
	Wind	1,150.6	4.9%	1,097.6	0.0	2,248.2	6.7%
	WMAAC Total	23,409.2	100.0%	10,795.1	597.0	33,607.3	100.0%
Non-MAAC	Combined Cycle	16,823.9	12.6%	21,446.3	0.0	38,270.2	23.3%
	Combustion Turbine	20,742.7	15.6%	729.1	0.0	21,471.8	13.1%
	Diesel	494.1	0.4%	147.5	10.3	631.3	0.4%
	Hydroelectric	5,092.6	3.8%	265.2	0.0	5,357.8	3.3%
	Nuclear	20,049.3	15.1%	102.0	0.0	20,151.3	12.3%
	Solar	49.0	0.0%	1,556.6	0.0	1,605.6	1.0%
	Steam	64,287.2	48.3%	2,134.2	8,740.8	57,680.6	35.1%
	Storage	77.9	0.1%	345.6	0.0	423.5	0.3%
	Wind	5,443.6	4.1%	13,216.5	0.0	18,660.1	11.4%
	Non-MAAC Total	133,060.3	100.0%	39,942.9	8,751.1	164,252.1	100.0%
All Areas	Total	200,808.1		65,424.0	12,841.8	253,390.3	

12 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.[13] 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).

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.

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

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 applied to the MW expected to go into service and is based on the historical incidence of projects dropping out of the queue at the impact study stage.[14] The impact and facilities studies are performed using the full amount of planned generation in the queues.

13 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>.
14 See PJM Manual 14B. "PJM Region Transmission Planning Process," Revision 30 (February 26, 2015), p.70.

Table 12-14 shows the milestone due when projects were withdrawn, for all withdrawn projects. Of the projects withdrawn, 46.6 percent were withdrawn before the Impact Study was completed. Once an Interconnection Service Agreement (ISA) (or a Wholesale Market Participation Agreement (WMPA)[15]) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted.[16] As expected, withdrawing at or beyond this point is uncommon; 197 projects, or 12.8 percent, of all projects withdrawn were done so after reaching this milestone.

15 "Generators planning to connect to the local distribution systems at locations that are not under FERC jurisdiction and wish to participate in PJM's market need to execute a PJM Wholesale Market Participation Agreement (WMPA)…" instead of an ISA. See PJM Manual 14C. "Generation and Transmission Interconnection Facility Construction," Revision 08 (December 20, 2012), p.8.
16 See PJM Manual 14C. "Generation and Transmission Interconnection Facility Construction," Revision 08 (December 20, 2012), p.22.

Table 12-14 Last milestone completed at time of withdrawal (January 1, 1997 through March 31, 2015)

Milestone Completed	Projects Withdrawn	Percent
Never Started	148	9.6%
Feasibility Study	568	37.0%
Impact Study	516	33.6%
Facilities Study	105	6.8%
Interconnection Service Agreement (ISA)	145	9.5%
Construction Service Agreement (CSA) or beyond	52	3.4%
Total	1,534	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 928 days, or 2.5 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 686 days. For withdrawn projects, there is an average time of 676 days between entering a queue and withdrawing.

Table 12-15 Average project queue times (days) at March 31, 2015

Status	Average	Standard Deviation	Minimum	Maximum
Active	1,000	693	33	3,890
In-Service	928	673	1	4,024
Suspended	1,894	722	508	3,652
Under Construction	1,845	903	398	6,380
Withdrawn	676	660	6	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 540 projects in the queue as of March 31, 2015, 94 had a completed feasibility study and 179 were under construction.

Table 12-16 PJM generation planning summary: at March 31, 2015

Milestone Completed	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Not Started	52	9.6%	592	2,555
Feasibility Study	94	17.4%	805	2,223
Impact Study	104	19.3%	1,265	3,890
Facilities Study	20	3.7%	1,845	3,291
Interconnection Service Agreement (ISA)	20	3.7%	814	1,965
Construction Service Agreement (CSA)	3	0.6%	586	605
Under Construction	179	33.1%	1,845	6,380
Suspended	68	12.6%	1,894	3,652
Total	540	100.0%		

Role of Transmission Owners in Transmission Planning Study Phase

According to PJM Manual 14A PJM, in coordination with the TOs, conducts the feasibility, system impact and facilities studies for every interconnection queue project. A facilities study is required only for new generation and major upgrades and is the study in which the TO is most involved. For a facilities study, the interconnected TO (ITO), as well as any other affected TOs, is required to conduct their own facilities study and provide a summary and results to PJM, who compiles them, along with the customer's and PJM's study results into a single facilities report.[17]

Of 548 active projects analyzed, the developer and TO are part of the same company for 46 of the projects, or 8,568.8 MW of a total 50,365.1 MW. 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 part of the same company. There is also 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.

Table 12-17 is a summary of the number of projects and total MW, by transmission owner parent company, identified as having the developer and

17 See PJM. "Manual 14A, "Generation and Transmission Interconnection Process," Revision 17, (January 22, 2015), <http://www.pjm.com/documents/manuals.aspx>

transmission owner being part of the same company. Dominion has five related projects, but they account for 4,637.5 MW, which is 60.8 percent of its total MW currently in the queue. In contrast, AEP has 12 related projects, but they account for only 4.3 percent of its total MW currently in the queue.

Table 12-17 Summary of project developer relationship to transmission owner

	Related to Developer		Unrelated to Developer	
Parent Company	Number of Projects	Total MW	Number of Projects	Total MW
AEP	12	302.9	70	6,696.0
DAY	2	32.5	7	180.9
DLCO	0	0.0	1	97.0
Dominion	5	4,637.5	37	2,987.3
Duke	3	50.0	6	528.2
Essential Power	0	0.0	1	135.0
Exelon	5	567.6	60	4,282.6
First Energy	2	1,616.0	179	14,032.1
Pepco	0	0.0	83	5,754.8
PPL	0	0.0	30	5,181.6
PSEG	17	1,362.3	28	1,920.9
Total	46	8,568.8	502	41,796.3

These projects are shown by fuel type in Table 12-18. Natural gas generators comprise 55.8 percent of the total related MW in this table. Developers of the coal and nuclear projects are almost entirely related to the TO, with 95.1 percent and 98.8 percent of MW. None of the other fuel types have more than 1.4 percent of MW in development related to the TO.

Table 12-18 Developer-transmission owner relationship by fuel type

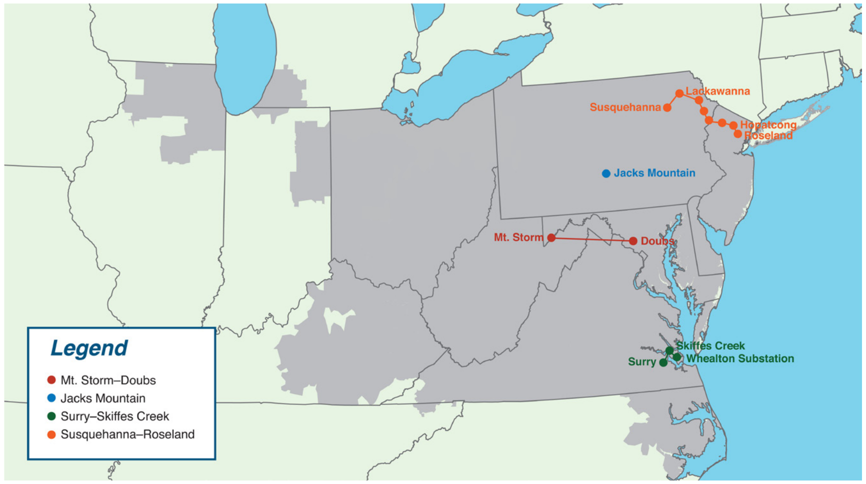
				MW by Fuel Type											
Parent Company	Transmission Owner	Related to Developer	Number of Projects	Biomass	Coal	Hydro	Landfill Gas	Natural Gas	Nuclear	Oil	Other	Solar	Storage	Wind	Total MW
AEP	AEP	Related	12		108.0			104.5	83.0			7.4			302.9
		Unrelated	70	45.0	92.0	9.0	24.0	5,466.0				27.3		1,032.8	6,696.0
DAY	DAY	Related	2		32.5										32.5
		Unrelated	7			112.0						8.9		60.0	180.9
DLCO	DLCO	Unrelated	1					97.0							97.0
Dominion	Dominion	Related	5					3,066.0	1,570.0					1.5	4,637.5
		Unrelated	37	50.0			11.0	1,947.0				777.6	32.0	169.7	2,987.3
Duke	DEOK	Related	3		50.0										50.0
		Unrelated	6					513.0				15.2			528.2
Essential Power	Essential Power	Unrelated	1					135.0							135.0
Exelon	BGE	Related	2					230.0				7.6			237.6
		Unrelated	6	25.0			4.0				132.0	2.0			163.0
	ComEd	Unrelated	46			22.7	28.6	2,491.0				4.2		551.9	3,098.4
	PECO	Related	3						330.0						330.0
		Unrelated	8				13.2	1,008.0							1,021.2
PSEG	PSEG	Related	17					1,356.0				6.3			1,362.3
		Unrelated	28				3.0	1,861.8				56.1			1,920.9
First Energy	APS	Related	2		1,590.0			26.0							1,616.0
		Unrelated	44			74.5	4.0	2,682.0				57.7		151.7	2,969.9
	ATSI	Unrelated	11				0.4	3,620.0			135.0			67.3	3,822.7
	JCPL	Unrelated	82					2,475.0				227.5			2,702.5
	Met-Ed	Unrelated	7					891.5	24.0	401.0		1.1			1,317.6
	PENELEC	Unrelated	35			45.3	1.5	3,099.0				5.1		68.4	3,219.3
Pepco	AECO	Unrelated	23				0.3	1,709.5				27.1		48.3	1,785.1
	DPL	Unrelated	53	15.9				1,315.2				237.4		36.3	1,604.7
	Pepco	Unrelated	7					2,365.0							2,365.0
PPL	PPL	Unrelated	30	16.0			5.0	4,993.0				50.1	0.0	117.5	5,181.6
Total		Related	46	0.0	1,780.5	0.0	0.0	4,782.5	1,983.0	0.0	0.0	21.3	0.0	1.5	8,568.8
		Unrelated	502	151.9	92.0	263.5	95.0	36,669.0	24.0	401.0	267.0	1,497.2	32.0	2,303.8	41,796.3

Regional Transmission Expansion Plan (RTEP)

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



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.[18]

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.[19]

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 March 31, 2015, 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.[20]

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.[21]

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.[22] 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.

18 See Dominion "*Mt. Storm-Doubs*," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/mount-storm-doubs.aspx>
19 See "Jacks Mountain," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/jacks-mountain.aspx>.
20 See "Susquehanna-Roseland," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/susquehanna-roseland.aspx>.
21 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>.
22 See PJM. "Manual 3a: Energy Management System (EMS) Model Updates and Quality Assurance (QA), Revision 9 (January 22, 2015).

Table 12-19 Transmission facility outage request duration: January through March of 2014 and 2015

	2014 (Jan - Mar)		2015 (Jan - Mar)	
Days	Number of Outage Requests	Percent	Number of Outage Requests	Percent
<=5	3,260	77.6%	3,226	74.9%
>5 & <=30	682	16.2%	757	17.6%
>30	260	6.2%	325	7.5%
Total	4,202	100.0%	4,308	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 12-20.[23]

Table 12-20 PJM transmission facility request status definition

Days	Request Submitted Date	Ticket Status
<=5	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
> 5 & <=30	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
>30	The earlier of 1) February 1st ,2) the 1st of the month six months prior to the starting month 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 the outage	Late
	After 8:00AM three days prior to the outage	Past Deadline

Table 12-21 shows a summary of requests with on time received status. In the first three months of 2015, 50.4 percent of outage requests received were on time, compared to 48.6 percent in the first three months of 2014.

Table 12-21 Transmission outage requests with on time status: January through March of 2014 and 2015

	2014 (Jan - Mar)			2015 (Jan - Mar)		
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	3,260	1,592	48.8%	3,226	1,650	51.1%
>5 & <=30	682	353	51.8%	757	402	53.1%
>30	260	99	38.1%	325	121	37.2%
Total	4,202	2,044	48.6%	4,308	2,173	50.4%

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 12-22 shows emergency request statistics. Overall, 15.3 percent of all outage requests submitted in the first three months of 2015 were for emergency outages.

Table 12-22 Emergency transmission outage summary: January through March of 2014 and 2015

	2014 (Jan - Mar)			2015 (Jan - Mar)		
Days	Number of Outage Requests	Number of Emergency Outage Requests	Percent of Emergency Outage Requests	Number of Outage Requests	Number of Emergency Outage Requests	Percent of Emergency Outage Requests
<=5	3,260	618	19.0%	3,226	517	16.0%
>5 & <=30	682	105	15.4%	757	109	14.4%
>30	260	51	19.6%	325	31	9.5%
Total	4,202	774	18.4%	4,308	657	15.3%

For late tickets, the outage request may be denied or cancelled if it is expected to cause congestion. Table 12-23 shows a summary of requests which PJM determined might cause congestion. Overall, 10.1 percent of all tickets submitted in the first three months of 2015 were tickets that might cause congestion, compared to 8.7 percent in the first three months of 2014.

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

Table 12-23 Transmission facility outage ticket congestion status summary: January through March of 2014 and 2015

	2014 (Jan - Mar)			2015 (Jan - Mar)		
Submission Status	Number of Outage Requests	Number of Outage Requests That Might Cause Congestion	Percent of Outage Requests That Might Cause Congestion	Number of Outage Requests	Number of Outage Requests That Might Cause Congestion	Percent of Outage Requests That Might Cause Congestion
Late & Emergency	23	768	3.0%	24	655	3.7%
Late & Non-Emergency	59	1,390	4.2%	74	1,480	5.0%
On Time & Emergency	0	6	0.0%	0	2	0.0%
On Time & Non-Emergency	282	2,038	13.8%	339	2,171	15.6%
Total	364	4,202	8.7%	437	4,308	10.1%

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage (Table 12-22). The table shows the summary of all the outage requests planned in the first months of 2014 and 2015 which were approved and then cancelled or rescheduled by TOs at least once in history. In the first three months of 2015, 10.1 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 16.3 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. Compared to the first three months of 2014, 9.3 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 15.8 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs.

Table 12-24 Rescheduled transmission outage request summary: January through March of 2014 and 2015

	2014 (Jan - Mar)					2015 (Jan - Mar)				
Days	Number of Outage Requests	Number of Approved and Revised Outage Requests	Percent of Approved and Revised Outage Requests	Number of Approved and Cancelled Outage Requests	Percent of Approved and Cancelled Outage Requests	Number of Outage Requests	Number of Approved and Revised Outage Requests	Percent of Approved and Revised Outage Requests	Number of Approved and Cancelled Outage Requests	Percent of Approved and Cancelled Outage Requests
<=5	3,260	276	8.5%	568	17.4%	3,226	327	10.1%	589	18.3%
>5 & <=30	682	89	13.1%	74	10.9%	757	68	9.0%	74	9.8%
>30	260	25	9.6%	21	8.1%	325	41	12.6%	41	12.6%
Total	4,202	390	9.3%	663	15.8%	4,308	436	10.1%	704	16.3%

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.[24] 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.[25] 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.

24 PJM. "Manual 3: Transmission Outages," Revision 46 (December 1, 2014), p. 63.
25 PJM. "Manual 3: Transmission Outages," Revision: 46 (December 1, 2014), p. 64.