Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** As of December 31, 2015, 85,323.1 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 187,744.2 MW as of December 31, 2015. Of the capacity in queues, 6,246.5 MW, or 7.3 percent, are uprates and the rest are new generation. Wind projects account for 15,698.8 MW of nameplate capacity or 18.4 percent of the capacity in the queues. Combined-cycle projects account for 56,827.9 MW of capacity or 66.6 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-6, 27,689.0 MW have been, or are planned to be, retired between 2011 and 2020. Of that, 3,912.3 MW are planned to retire after 2015. In 2015, 9,859.7 MW were retired, of which 7,661.8 MW were coal units. The coal unit retirements were a result of low gas prices and the EPA's Mercury and Air Toxics Standards (MATS) for some units.
- **Generation Mix.** A significant shift in the distribution of unit types within the PJM footprint continues as natural gas fired units enter the queue and steam units retire. While only 2,007.0 MW of coal fired steam capacity are currently in the queue, 60,717.7 MW of gas fired capacity are in the queue. 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 at least in part as a result 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. Excluding currently active projects and projects currently under construction, 2,275 projects, representing 327,280.0 MW, have completed the queue process since its inception. Of those, 605 projects, 41,021.9 MW, went into service. Of the projects that entered the queue process, 87.5 percent of the MW withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- Feasibility, impact and facilities studies may be delayed for reasons including disputes with developers, circuit and network issues and retooling as a result of projects being withdrawn. The Earlier Queue Submittal Task Force (EQSTF) was established in August 2015 to address delays.[2]
- As defined in the tariff, a transmission owner (TO) is an "entity that owns, leases or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce under the tariff."[3] 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 and when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of a merchant transmission developer which is a competitor of the transmission owner.

1 See PJM, OATT Parts IV & VI.

2 See Earlier Queue Submittal Task Force at <http://www.pjm.com/committees-and-groups/task-forces/eqstf.aspx>

3 See PJM, OATT, Part I, § 1 "Definitions"

Regional Transmission Expansion Plan (RTEP)

- Artificial Island is an area in southern New Jersey that includes nuclear units at Salem and at Hope Creek in the PSEG Zone. On April 29, 2013, PJM issued a request for proposal (RFP), seeking technical solutions to improve stability issues and operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations in this area. On July 30, 2015, the PJM Board of Managers accepted PJM's recommendation to assign the project to LS Power, a merchant developer, PSEG, and PHI with a total cost estimate between $263M and $283M.[4,5]
- On October 25, 2012, Schedule 12 of the tariff and Schedule 6 of the OA were changed to address FERC Order No. 1000 reforms to the cost allocation requirements for local and regional transmission planning projects that were formerly defined in Order No. 890. The new approach was applied for the first time to the 2013 RTEP. Since then, some developers have raised concern with the cost allocations using the new solution based dfax method.

Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects, which are intended to resolve multiple reliability criteria violations and congestion issues and which may have substantial impacts on energy and capacity markets. There is currently only one backbone project under development, 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 outage requests according to rules in PJM's Manual 3 to decide if the outage is on time, late, or past its deadline and whether or not they will allow the outage.[6]
- There were 19,593 transmission outage requests submitted for 2015. Of the requested outages, 79.2 percent were planned for five days or shorter and 4.9 percent were planned for longer than 30 days. Of the requested outages, 49.1 percent were late according to the rules in PJM's Manual 3.
- There were 19,614 transmission outage requests submitted for 2014. Of the requested outages, 79.8 percent were planned for five days or shorter and 5.4 percent were planned for longer than 30 days. Of the requested outages, 48.7 percent were late according to the rules in PJM's Manual 3.

Recommendations

The MMU recommends improvements to the planning process.

- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- 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 rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Low. New recommendation. Status: Not adopted.)

4 See "Artificial Island Recommendations," presented at the TEAC meeting on April 28, 2015 at <http://www.pjm.com/~/media/committees-groups/committees/teac/20150428-ai/20150428-artificial-island-recommendations.ashx>

5 See letter from Terry Boston concerning the Artificial Island Project at <http://www.pjm.com/~/media/documents/reports/board-statement-on-artificial-island-project.ashx>

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

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. 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.[7] (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: Partially 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: Partially adopted, 2014.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and merchant transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. (Priority: Medium. First reported Q2, 2015. Status: Not adopted.)
- The MMU recommends consideration of changing the minimum distribution factor in the allocation from .01 to .00 and adding a threshold minimum impact on the load on the line. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. New Recommendation. Status: Not adopted.)

7 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000, <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a total project cost cap, 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, whether there is more risk associated with the generation or transmission alternatives, 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 for new generation investments 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 through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and merchant transmission providers. PJM should enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. Another element of opening competition would be to consider transmission owners' 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 the RTEP process and be made available to all providers on equal terms.

There are currently no market incentives for transmission owners to submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR Auction bid submission dates and are late for the Day-Ahead Energy Market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers.

Planned Generation and Retirements

Planned Generation Additions

Expected net revenues provide incentives to build new generation to serve PJM markets. The amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM energy, capacity and ancillary service markets. On December 31, 2015, 85,323.1 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 187,744.2 MW as of December 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 2015, 3,808.4 MW of nameplate capacity went into service in PJM.

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

Year	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	3,808.4

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 reset to six months, starting with Queue Y2. Queue AB2 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. 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.[8] When a project is suspended, PJM extends the scheduled milestones by the duration of the suspension. If, at any time, a milestone is not met, PJM will initiate the termination of the Interconnection Service Agreement (ISA) and the corresponding cancellation costs must be paid by the customer.[9]

Table 12-2 shows MW in queues by expected completion date and MW changes in the queues between December 31, 2014 and December 31, 2015, for ongoing projects, i.e. projects with the status active, under construction or suspended.[10] Projects that are already in service are not included here. The total MW in queues increased by 17,214.7 MW, or 25.3 percent, from 68,108.4 MW at the end of 2014. The change was the result of 36,808.3 MW in new projects entering the queue, 14,751.6 MW in projects withdrawing, and 3,899.3 MW going into service. The remaining difference is the result of projects adjusting their expected MW.[11]

Table 12-2 Queue comparison by expected completion year (MW): December 31, 2014 vs. December 31, 2015[12]

			Annual Change	
Year	As of 12/31/2014	As of 12/31/2015	MW	Percent
2014	4,604.5	0.0	(4,604.5)	NA
2015	13,992.5	9,641.9	(4,350.6)	(45.1%)
2016	16,974.2	15,085.7	(1,888.5)	(12.5%)
2017	14,075.1	12,442.3	(1,632.8)	(13.1%)
2018	12,587.0	13,403.6	816.6	6.1%
2019	3,051.0	21,461.3	18,410.3	85.8%
2020	1,152.0	11,444.3	10,292.3	89.9%
2021	78.2	0.0	(78.2)	NA
2022	0.0	250.0	250.0	100.0%
2024	1,594.0	1,594.0	0.0	0.0%
Total	68,108.4	85,323.1	17,214.7	25.3%

Table 12-3 shows the yearly project status changes in more detail and how scheduled queue capacity has changed between December 31, 2014, and December 31, 2015. For example, 36,808.3 MW entered the queue in 2015, 30,806.2 MW of which are currently active and 5,823.2 MW of which were withdrawn before the year ended. Of the total 41,729.0 MW marked as active at the beginning of the year, 8,005.7 MW were withdrawn, 19,783.8 MW started construction, and 602.1 MW went into service by the end of the year. The Under Construction column shows that 927.6 MW came out of suspension and 11,645.5 MW began construction in

8 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>.

9 PJM does not track the duration of suspensions or PJM termination of projects.

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

11 PJM put a new planning system database into production in late 2015. There are some minor differences in reported data between this report and 2014 as a result.

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

2015, in addition to the 15,690.1 MW of capacity that maintained the status under construction from the previous year.

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

		Status at 12/31/2015				
Status at 12/31/2014	Total at 12/31/2014	Active	Suspended	Under Construction	In Service	Withdrawn
(Entered in 2015)		30,806.2	0.0	10.9	168.0	5,823.2
Active	41,729.0	19,783.8	33.9	11,645.5	602.1	8,005.7
Suspended	4,751.8	200.0	3,020.2	927.6	0.0	544.0
Under Construction	21,627.6	628.0	1,644.9	15,690.1	3,129.2	378.8
In Service	38,341.7	932.1	0.0	0.0	37,122.7	0.0
Withdrawn	274,630.6	0.0	0.0	0.0	0.0	271,506.4
Total at 12/31/2015		52,350.1	4,698.9	28,274.1	41,021.9	286,258.0

Table 12-4 Capacity in PJM queues (MW): At December 31, 2015[13]

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	14,620.7	19,266.2
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	1,189.6	0.0	0.0	17,961.8	19,151.4
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	98.9	0.0	0.0	485.2	584.1
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	186.0	318.8	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	1,668.2	437.0	0.0	5,466.8	7,572.0
P Expired 31-Jan-06	190.5	3,064.7	62.5	210.0	5,110.5	8,638.2
Q Expired 31-Jul-06	0.0	3,147.9	1,594.0	0.0	9,791.7	14,533.6
R Expired 31-Jan-07	160.0	1,886.4	488.3	800.0	19,420.6	22,755.3
S Expired 31-Jul-07	256.0	3,512.7	246.9	120.0	12,396.5	16,532.0
T Expired 31-Jan-08	550.0	1,779.0	2,168.0	300.0	22,738.3	27,535.3
U Expired 31-Jan-09	668.0	837.3	681.9	320.0	30,829.6	33,336.8
V Expired 31-Jan-10	1,483.7	1,824.1	919.1	550.0	12,036.4	16,813.3
W Expired 31-Jan-11	1,323.0	1,918.6	1,359.7	1,410.0	18,066.0	24,077.3
X Expired 31-Jan-12	2,944.0	436.9	8,962.7	366.8	17,634.0	30,344.5
Y Expired 30-Apr-13	1,705.1	533.8	4,579.6	592.5	18,354.7	25,765.5
Z Expired 30-Apr-14	4,081.3	293.7	4,393.5	22.4	5,652.8	14,443.7
AA1 Expired 31-Oct-14	7,651.3	33.4	2,182.1	7.3	2,128.3	12,002.4
AA2 Expired 30-Apr-15	11,874.6	0.0	7.5	0.0	4,195.8	16,077.9
AB1 Expired 31-Oct-15	18,802.9	0.0	3.4	0.0	1,673.9	20,480.2
AB2 Through 31-Dec-15	473.7	0.0	0.0	0.0	0.0	473.7
Total	52,350.1	41,021.9	28,274.1	4,698.9	286,258.0	412,129.4

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 December 31, 2015, there are 85,323.1 MW of capacity in queues that are not yet in service, of which 5.5 percent are suspended, 33.1 percent are under construction and 61.4 percent have not begun construction.

13 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, and control zone.[14] As of December 31, 2015, 85,323.1 MW of capacity were in generation request queues for construction through 2024, compared to 79,603.8 MW at September 30, 2015.[15] Table 12-5 also shows the planned retirements for each zone.

Table 12-5 Queue capacity by LDA, control zone and fuel (MW): At December 31, 2015[16]

LDA	Zone	BioMass	CC	CT	Diesel	Fuel Cell	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total Queue Capacity	Planned Retirements
EMAAC	AECO	0.0	1,746.0	239.5	0.0	1.5	0.0	0.0	60.2	0.0	21.0	373.0	2,441.2	8.0
	DPL	0.0	742.0	7.0	2.0	0.0	0.0	0.0	405.1	0.0	20.0	749.6	1,925.7	34.0
	JCPL	0.0	3,376.2	0.0	0.6	0.0	0.0	0.0	482.6	0.0	180.0	0.0	4,039.4	614.5
	PECO	0.0	3,626.0	0.0	8.6	0.0	0.0	50.0	0.0	0.0	40.8	0.0	3,725.4	50.8
	PSEG	0.0	1,727.0	671.0	10.6	0.0	0.0	0.0	119.6	24.0	2.0	0.0	2,554.2	611.0
	RECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EMAAC Total	0.0	11,217.2	917.5	21.8	1.5	0.0	50.0	1,067.5	24.0	263.8	1,122.6	14,685.9	1,318.3
SWMAAC	BGE	0.0	0.0	256.0	30.3	0.0	0.4	0.0	23.1	132.0	20.1	0.0	461.9	209.0
	Pepco	0.0	2,642.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,642.6	1,204.0
	SWMAAC Total	0.0	2,642.6	256.0	30.3	0.0	0.4	0.0	23.1	132.0	20.1	0.0	3,104.5	1,413.0
WMAAC	Met-Ed	0.0	2,311.5	34.1	0.0	0.0	0.0	0.0	3.0	0.0	0.0	0.0	2,348.6	0.0
	PENELEC	0.0	3,664.5	1,420.8	181.7	0.0	40.0	0.0	13.5	0.0	40.0	493.3	5,853.8	0.0
	PPL	16.0	7,195.0	19.9	24.9	0.0	0.0	0.0	16.0	0.0	30.0	466.5	7,768.3	0.0
	WMAAC Total	16.0	13,171.0	1,474.8	206.6	0.0	40.0	0.0	32.5	0.0	70.0	959.8	15,970.7	0.0
Non-MAAC	AEP	0.0	7,234.0	142.0	13.0	0.0	134.0	102.0	119.2	211.0	114.0	6,602.0	14,671.2	0.0
	AP	0.0	4,335.4	0.0	132.8	0.0	0.0	0.0	354.8	1,726.5	73.0	1,251.8	7,874.3	0.0
	ATSI	0.0	5,947.0	0.0	65.3	0.0	0.0	0.0	0.0	0.0	32.5	518.0	6,562.8	94.0
	ComEd	0.0	4,949.3	590.0	58.7	0.0	22.7	80.0	0.0	27.0	111.1	3,472.5	9,311.3	510.0
	DAY	1.9	0.0	0.0	0.0	0.0	0.0	0.0	25.9	12.0	20.0	300.0	359.8	0.0
	DEOK	0.0	513.0	0.0	6.4	0.0	112.0	0.0	125.0	50.0	10.0	0.0	816.4	0.0
	DLCO	0.0	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	225.0	0.0
	Dominion	62.5	5,463.4	60.0	14.0	0.0	0.0	1,594.0	1,891.3	0.0	34.0	1,472.1	10,591.3	325.0
	EKPC	0.0	1,150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,150.0	149.0
	Non-MAAC Total	64.4	29,797.1	792.0	290.2	0.0	268.7	1,776.0	2,516.2	2,026.5	414.6	13,616.4	51,562.1	1,078.0
Total		80.4	56,827.9	3,440.3	548.9	1.5	309.1	1,826.0	3,639.3	2,182.5	768.5	15,698.8	85,323.1	3,809.3

A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units enter the queue and steam units retire. While 60,717.7 MW of gas fired capacity are in the queue, there are only 2,007.0 MW of coal fired steam capacity in the queue. The only new coal project currently in the queue is the new Hatfield unit, with 1,710 MW of capacity. This project, which entered the queue in October 2014 and is already under construction, is intended to replace three coal units retired in October 2013 at the same location. With respect to retirements, 2,467.0 MW of coal fired steam capacity and 282.8 MW of natural gas capacity are slated for deactivation between now and 2020. 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.

14 Unit types designated as reciprocating engines are classified as diesel.

15 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 15,698.8 MW of wind resources and 3,639.3 MW of solar resources, the 85,323.1 MW currently active in the queue would be reduced to 69,408.8 MW.

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

Planned Retirements

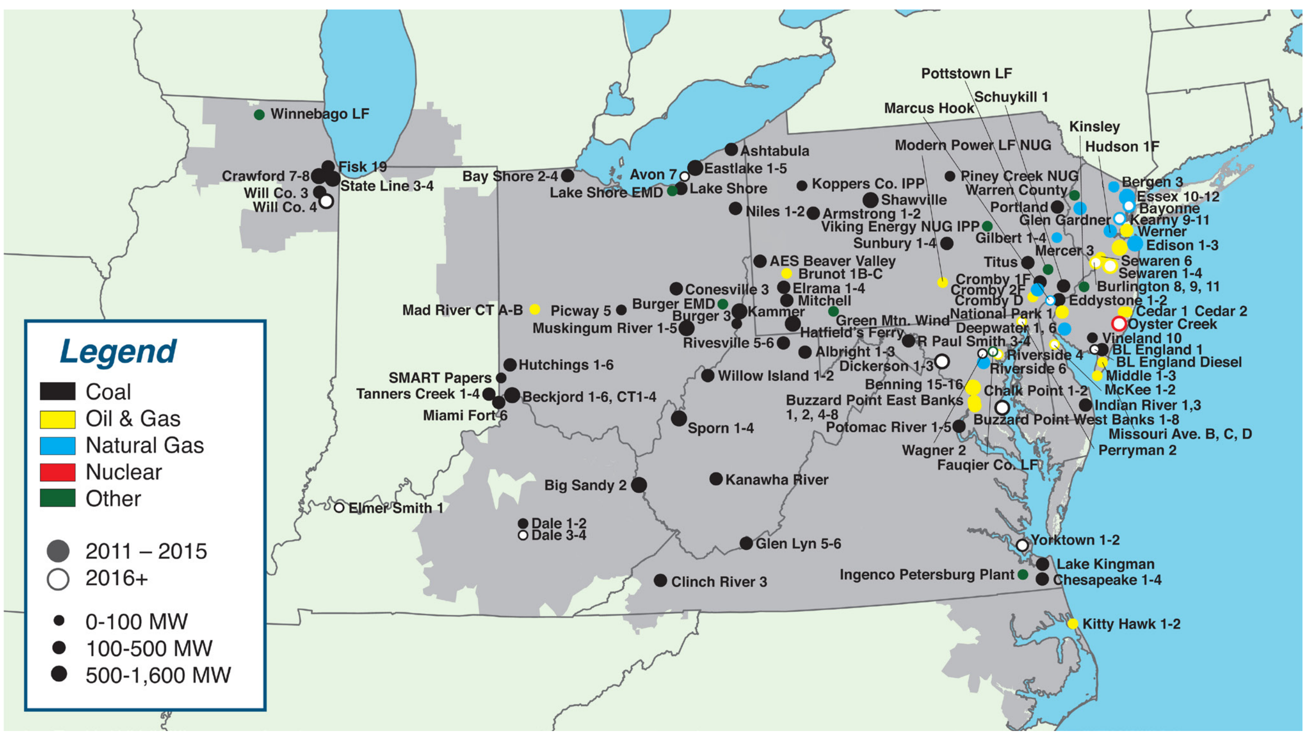
As shown in Table 12-6, 27,689.0 MW have been, or are planned to be, retired between 2011 and 2020.[17] Of that, 3,912.3 MW are planned to retire after 2015. In 2015, 9,859.7 MW were retired, of which 7,661.8 MW were coal units. The coal unit retirements were a result of low gas prices and the EPA's Mercury and Air Toxics Standards (MATS) for some units.

Table 12-6 Summary of PJM unit retirements by fuel (MW): 2011 through 2020

	Coal	Diesel	Heavy Oil	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Wind	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	2,589.9	2.9	166.0	0.0	3.8	85.0	0.0	0.0	0.0	8.0	2,855.6
Retirements 2014	2,427.0	50.0	0.0	184.0	15.3	0.0	294.0	0.0	0.0	0.0	2,970.3
Retirements 2015	7,661.8	10.3	0.0	644.2	2.0	212.0	1,319.0	0.0	10.4	0.0	9,859.7
Planned Retirements Post-2015	2,467.0	59.0	108.0	0.0	2.0	0.0	661.8	614.5	0.0	0.0	3,912.3
Total	21,596.6	122.2	274.0	828.2	23.1	1,148.7	3,047.3	614.5	10.4	24.0	27,689.0

A map of the retirements between 2011 and 2020 is shown in Figure 12-1.

Figure 12-1 Map of PJM unit retirements: 2011 through 2020



17 See PJM "Generator Deactivation Summary Sheets," at <http://www.pjm.com/planning/generation-deactivation/gd-summaries.aspx> (February 23, 2016).

The list of pending retirements is shown in Table 12-7.

Table 12-7 Planned retirement of PJM units: as of December 31, 2015

Unit	Zone	ICAP (MW)	Fuel	Unit Type	Projected Deactivation Date
Perryman 2	BGE	51.0	Diesel	Combustion Turbine	01-Jan-16
Fauquier County Landfill	Dominion	2.0	Diesel	Diesel	29-Feb-16
Yorktown 1-2	Dominion	323.0	Coal	Steam	31-Mar-16
Dale 3-4	EKPC	149.0	Coal	Steam	16-Apr-16
Avon Lake 7	ATSI	94.0	Coal	Steam	16-Apr-16
BL England Diesels	AECO	8.0	Diesel	Diesel	31-May-16
Riverside 4	BGE	74.0	Natural gas	Steam	01-Jun-16
McKee 1-2	DPL	34.0	Heavy Oil	Combustion Turbine	31-May-17
Sewaren 1-4	PSEG	453.0	Kerosene	Combustion Turbine	01-Nov-17
Will County 4	ComEd	510.0	Coal	Steam	31-May-18
Bayonne Cogen Plant (CC)	PSEG	158.0	Natural gas	Steam	01-Nov-18
MH50 Marcus Hook Co-gen	PECO	50.8	Natural gas	Steam	13-May-19
Chalk Point 1-2	Pepco	667.0	Coal	Steam	31-May-19
Dickerson 1-3	Pepco	537.0	Coal	Steam	31-May-19
Elmer Smith U1	External	52.0	Coal	Steam	01-Jun-19
Oyster Creek	JCPL	614.5	Nuclear	Nuclear	31-Dec-19
Wagner 2	BGE	135.0	Coal	Steam	01-Jun-20
Total		3,912.3			

Table 12-8 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2020, while Table 12-9 shows these retirements by state. The majority, 78.0 percent, of all MW retiring during this period are coal steam units. These units have an average age of 56.0 years and an average size of 166.1 MW. Half of them, 50.5 percent, are located in either Ohio or Pennsylvania. Retirements have generally consisted of smaller subcritical coal steam units and those without adequate environmental controls to remain viable beyond 2015.

Table 12-8 Retirements by fuel type: 2011 through 2020

	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Coal	130	166.1	56.0	21,596.6	78.0%
Diesel	7	17.5	42.7	122.2	0.4%
Heavy Oil	4	68.5	57.5	274.0	1.0%
Kerosene	20	41.4	45.5	828.2	3.0%
Landfill Gas	6	3.9	15.8	23.1	0.1%
Light Oil	15	76.6	43.8	1,148.7	4.1%
Natural Gas	51	59.8	46.3	3,047.3	11.0%
Nuclear	1	614.5	50.0	614.5	2.2%
Wind	1	10.4	15.0	10.4	0.0%
Wood Waste	2	12.0	23.5	24.0	0.1%
Total	237	116.8	50.4	27,689.0	100.0%

Table 12-9 Retirements (MW) by fuel type and state: 2011 through 2020

State	Coal	Diesel	Heavy Oil	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Wind	Wood Waste	Total
DC	0.0	0.0	0.0	0.0	0.0	788.0	0.0	0.0	0.0	0.0	788.0
DE	254.0	0.0	34.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	288.0
IL	2,134.0	0.0	0.0	0.0	6.4	0.0	0.0	0.0	0.0	0.0	2,140.4
IN	982.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0
KY	1,047.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,047.0
MD	1,454.0	51.0	74.0	0.0	0.0	0.0	115.0	0.0	0.0	0.0	1,694.0
NC	0.0	0.0	0.0	0.0	0.0	31.0	0.0	0.0	0.0	0.0	31.0
NJ	136.0	8.0	0.0	828.2	4.7	212.0	2,680.5	614.5	0.0	0.0	4,483.9
OH	5,752.6	60.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,812.9
PA	5,145.0	0.0	166.0	0.0	10.0	117.7	251.8	0.0	10.4	24.0	5,724.9
VA	2,051.0	2.9	0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	2,055.9
WV	2,641.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,641.0
Total	21,596.6	122.2	274.0	828.2	23.1	1,148.7	3,047.3	614.5	10.4	24.0	27,689.0

Actual Generation Deactivations in 2015

Table 12-10 shows the units that were deactivated in 2015.

Table 12-10 Unit deactivations in 2015

Company	Unit Name	ICAP (MW)	Primary Fuel	Zone Name	Average Age (Years)	Retirement Date
Calpine Corporation	Cedar 1	44.0	Kerosene	AECO	43	28-Jan-15
First Energy	Eastlake 2	109.0	Coal	ATSI	62	06-Apr-15
First Energy	Eastlake 1	109.0	Coal	ATSI	62	09-Apr-15
First Energy	Eastlake 3	109.0	Coal	ATSI	61	10-Apr-15
First Energy	Ashtabula 5	210.0	Coal	ATSI	57	11-Apr-15
First Energy	Lake Shore 18	190.0	Coal	ATSI	53	13-Apr-15
First Energy	Lake Shore EMD	4.0	Diesel	ATSI	49	15-Apr-15
NRG Energy	Will County	251.0	Coal	ComEd	58	15-Apr-15
EKPC	Dale 1-2	46.0	Coal	EKPC	61	16-Apr-15
Calpine Corporation	Cedar 2	21.6	Kerosene	AECO	43	01-May-15
NRG Energy	Gilbert 1-4	98.0	Natural gas	JCPL	45	01-May-15
NRG Energy	Glen Gardner 1-8	160.0	Natural gas	JCPL	44	01-May-15
Calpine Corporation	Middle 1-3	74.7	Kerosene	AECO	45	01-May-15
Calpine Corporation	Missouri Ave B, C, D	57.9	Kerosene	AECO	46	01-May-15
NRG Energy	Werner 1-4	212.0	Light oil	JCPL	43	01-May-15
PSEG	Bergen 3	21.0	Natural gas	PSEG	48	01-Jun-15
AEP	Big Sandy 2	800.0	Coal	AEP	46	01-Jun-15
PSEG	Burlington 8, 11	205.0	Kerosene	PSEG	48	01-Jun-15
AEP	Clinch River 3	230.0	Coal	AEP	54	01-Jun-15
PSEG	Edison 1-3	504.0	Natural gas	PSEG	44	01-Jun-15
PSEG	Essex 10-11	352.0	Natural gas	PSEG	44	01-Jun-15
PSEG	Essex 12	184.0	Natural gas	PSEG	43	01-Jun-15
AEP	Glen Lyn 5-6	325.0	Coal	AEP	65	01-Jun-15
AES Corporation	Hutchings 1-3, 5-6	271.8	Coal	DAY	65	01-Jun-15
AEP	Kammer 1-3	600.0	Coal	AEP	57	01-Jun-15
AEP	Kanawha River 1-2	400.0	Coal	AEP	62	01-Jun-15
PSEG	Mercer 3	115.0	Kerosene	PSEG	48	01-Jun-15
Duke Energy Kentucky	Miami Fort 6	163.0	Coal	DEOK	55	01-Jun-15
AEP	Muskingum River 1-5	1,355.0	Coal	AEP	60	01-Jun-15
PSEG	National Park 1	21.0	Kerosene	PSEG	46	01-Jun-15
AEP	Picway 5	95.0	Coal	AEP	60	01-Jun-15
PSEG	Sewaren 6	105.0	Kerosene	PSEG	50	01-Jun-15
AEP	Sporn 1-4	580.0	Coal	AEP	64	01-Jun-15
AEP	Tanners Creek 1-4	982.0	Coal	AEP	60	01-Jun-15
NRG Energy	Shawville 4	175.0	Coal	PENELEC	55	02-Jun-15
NRG Energy	Shawville 3	175.0	Coal	PENELEC	56	07-Jun-15
NRG Energy	Shawville 1	122.0	Coal	PENELEC	61	12-Jun-15
NRG Energy	Shawville 2	125.0	Coal	PENELEC	61	14-Jun-15
Portsmouth Genco	Lake Kingman	115.0	Coal	Dominion	27	19-Jun-15
AES Corporation	AES Beaver Valley	124.0	Coal	DLCO	28	01-Sep-15
First Energy	Burger EMD	6.3	Diesel	ATSI	43	18-Sep-15
NextEra Energy, Inc.	Arnold (Green Mountain) Wind Farm	10.4	Wind	PENELEC	15	05-Nov-15
Waste Management	Pottstown LF (Moser)	2.0	Landfill Gas	PECO	24	07-Dec-15
Total		9,859.7				

Generation Mix

As of December 31, 2015, PJM had an installed capacity of 187,744.2 MW (Table 12-11). This measure differs from capacity market installed capacity because it includes energy-only units, excludes all external units, and uses nameplate values for solar and wind resources.

Table 12-11 Existing PJM capacity: At December 31, 2015 (By zone and unit type (MW))[18]

Zone	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	901.9	507.7	22.6	0.0	0.0	0.0	41.7	815.9	0.0	7.5	2,297.3
AEP	4,900.0	3,682.2	77.1	0.0	1,071.9	2,071.0	0.0	18,897.8	4.0	2,103.2	32,807.2
AP	1,129.0	1,214.9	47.9	0.0	129.2	0.0	36.1	5,409.0	27.4	1,088.5	9,082.0
ATSI	685.0	1,617.4	74.0	0.0	0.0	2,134.0	0.0	5,813.0	0.0	0.0	10,323.4
BGE	0.0	840.0	18.4	0.0	0.0	1,716.0	0.0	2,995.5	0.0	0.0	5,569.9
ComEd	3,146.1	7,244.0	93.8	0.0	0.0	10,473.5	9.0	5,166.1	76.0	2,431.9	28,640.4
DAY	0.0	1,368.5	47.5	0.0	0.0	0.0	1.1	2,908.0	40.0	0.0	4,365.1
DEOK	47.2	654.0	0.0	0.0	0.0	0.0	0.0	3,730.0	10.0	0.0	4,441.2
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	134.7	7,890.0	0.0	0.0	24,717.5
DPL	1,498.5	1,820.4	96.1	30.0	0.0	0.0	4.0	1,620.0	0.0	0.0	5,069.0
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
JCPL	2,682.5	763.1	19.9	0.0	400.0	614.5	104.3	10.0	0.0	0.0	4,594.3
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	52.2	0.0	512.8	0.0	0.0	6,793.5	0.0	930.9	8,696.9
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	55.5	0.0	706.6	2,520.0	15.0	5,169.9	20.0	219.7	11,130.8
PSEG	3,846.3	1,132.0	11.1	0.0	5.0	3,493.0	134.0	2,050.1	2.0	0.0	10,673.5
RECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	31,932.0	28,865.9	824.1	30.0	8,152.1	33,732.1	482.9	76,763.0	180.4	6,781.7	187,744.2

Figure 12-2 and Table 12-12 show the age of PJM generators by unit type. Units older than 40 years comprise 66,781.6 MW, or 35.6 percent, of the total capacity of 187,744.2 MW.

Table 12-12 PJM capacity (MW) by age (years): At December 31, 2015

Age (years)	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 20	27,263.5	21,457.0	563.4	30.0	232.8	0.0	482.9	4,601.9	180.4	6,781.7	61,593.6
20 to 40	4,226.5	2,913.9	88.8	0.0	3,557.2	22,893.9	0.0	25,688.7	0.0	0.0	59,369.0
40 to 60	442.0	4,495.0	169.9	0.0	3,010.0	10,838.2	0.0	44,835.9	0.0	0.0	63,791.0
More than 60	0.0	0.0	2.0	0.0	1,352.1	0.0	0.0	1,636.5	0.0	0.0	2,990.6
Total	31,932.0	28,865.9	824.1	30.0	8,152.1	33,732.1	482.9	76,763.0	180.4	6,781.7	187,744.2

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

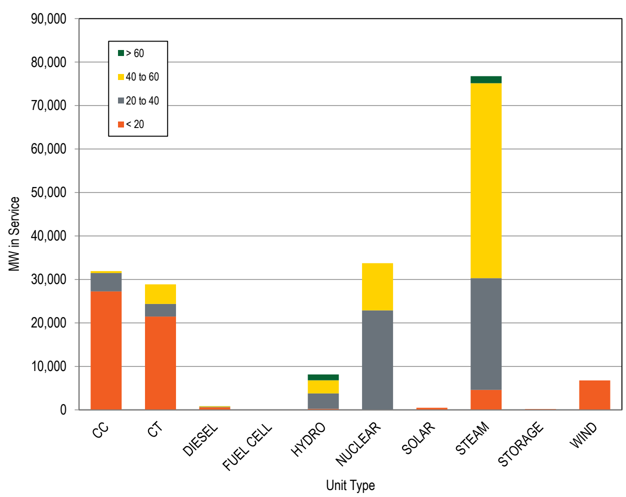


Table 12-13 shows the effect that expected retirements and new generation in the queues would have on the existing generation mix five years from now. The planned additions reflect the historical rates of completion, as shown in

18 The capacity described in this section refers to all nameplate installed capacity in PJM, regardless of whether the capacity entered the RPM auction. This table previously included external units.

Table 12-16. While there are currently 85,323.1 MW in the queue, historical patterns indicate that we can expect 36,713.3 MW to go into service, based on current status in the queue process. Even though 66,781.6 MW of the total capacity are more than 40 years old, only 3,912.3 MW of these are planned to retire within the next five years. The expected role of gas-fired generation depends on projects in the queues and retirement of coal-fired generation. Existing capacity in SWMAAC is currently 63.0 percent steam, which will be reduced to 46.2 percent by 2020 as a result of the addition of an expected 2,047.0 MW of planned CC capacity. The percentage of CC capacity would increase from 2.2 percent to 19.7 percent of capacity in SWMAAC in 2020. CC and CT generators would comprise 38.2 percent of SWMAAC capacity in 2020. In PJM as a whole, the percentage of capacity from renewables increases from 8.3 percent to 11.7 percent by 2020.

Table 12-13 Expected capacity (MW) in five years: as of December 31, 2015[19]

LDA	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	12,138.2	35.9%	3,923.7	0.0	16,061.9	42.2%
	Combustion Turbine	5,059.2	14.9%	277.3	0.0	5,336.5	14.0%
	Diesel	152.6	0.5%	11.9	8.0	156.5	0.4%
	Fuel Cell	30.0	0.1%	0.2	0.0	30.2	0.1%
	Hydroelectric	2,047.0	6.0%	0.0	0.0	2,047.0	5.4%
	Nuclear	8,654.3	25.6%	30.7	614.5	8,070.5	21.2%
	Solar	287.0	0.8%	656.2	0.0	943.2	2.5%
	Steam	5,475.1	16.2%	16.9	695.8	4,796.2	12.6%
	Storage	3.0	0.0%	67.4	0.0	70.4	0.2%
	Wind	7.5	0.0%	563.6	0.0	571.1	1.5%
	Total	33,853.9	100.0%	5,547.9	1,318.3	38,083.5	100.0%
SWMAAC	Combined Cycle	230.0	2.2%	2,047.0	0.0	2,277.0	19.7%
	Combustion Turbine	1,931.7	18.3%	205.9	0.0	2,137.6	18.5%
	Diesel	28.3	0.3%	24.4	0.0	52.7	0.5%
	Hydroelectric	0.0	0.0%	0.3	0.0	0.3	0.0%
	Nuclear	1,716.0	16.3%	0.0	0.0	1,716.0	14.9%
	Solar	0.0	0.0%	18.5	0.0	18.5	0.2%
	Steam	6,644.6	63.0%	106.1	1,413.0	5,337.7	46.2%
	Storage	0.0	0.0%	2.6	0.0	2.6	0.0%
	Total	10,550.6	100.0%	2,404.7	1,413.0	11,542.4	100.0%
WMAAC	Biomass	0.0	0.0%	12.9	0.0	12.9	0.0%
	Combined Cycle	3,918.9	16.7%	5,493.1	0.0	9,412.0	31.6%
	Combustion Turbine	1,430.2	6.1%	264.5	0.0	1,694.7	5.7%
	Diesel	149.1	0.6%	43.9	0.0	193.0	0.6%
	Hydroelectric	1,238.4	5.3%	28.1	0.0	1,266.5	4.2%
	Nuclear	3,325.0	14.2%	0.0	0.0	3,325.0	11.2%
	Solar	15.0	0.1%	26.1	0.0	41.1	0.1%
	Steam	12,163.4	52.0%	0.0	0.0	12,163.4	40.8%
	Storage	20.0	0.1%	17.5	0.0	37.5	0.1%
	Wind	1,150.6	4.9%	505.2	0.0	1,655.8	5.6%
	Total	23,410.6	100.0%	6,391.3	0.0	29,801.8	100.0%
RTO	Biomass	0.0	0.0%	51.8	0.0	51.8	0.0%
	Combined Cycle	15,644.9	13.0%	12,073.5	0.0	27,718.4	19.6%
	Combustion Turbine	20,444.8	17.0%	302.9	0.0	20,747.7	14.7%
	Diesel	494.1	0.4%	130.1	2.0	622.2	0.4%
	Hydroelectric	4,866.7	4.1%	193.4	0.0	5,060.1	3.6%
	Nuclear	20,036.8	16.7%	83.3	0.0	20,120.1	14.3%
	Solar	181.0	0.0	767.1	0.0	948.1	0.7%
	Steam	52,479.9	43.8%	1,522.1	1,128.0	52,874.0	37.5%
	Storage	157.4	0.1%	111.6	0.0	269.0	0.2%
	Wind	5,623.6	4.7%	7,133.7	0.0	12,757.3	9.0%
	Total	119,929.2	100.0%	22,369.5	1,130.0	141,168.6	100.0%
Total		187,744.2		36,713.3	3,861.3	220,596.3	

19 Percentages shown in Table 12-13 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.[20] 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). PJM staff reported on June 11, 2015, that due to these and other process improvements, the study backlog has been significantly reduced.[21] The Earlier Queue Submittal Task Force (EQSTF) was established in August 2015, to further address the issue.[22]

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 12-14 is an overview of PJM's study process. 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.

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.[23] The impact and facilities studies are performed using the full amount of planned generation in the queues. The actual withdrawal rates are shown in Table 12-15 and Table 12-16.

Table 12-15 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the projects withdrawn, 47.5 percent were withdrawn before the system impact study was completed. Once an Interconnection Service Agreement (ISA) or a Wholesale Market Participation Agreement (WMPA) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted.[24,25] Withdrawing at or beyond this point is uncommon; only 221 projects, or 13.2 percent, of all projects withdrawn were withdrawn after reaching this milestone.

Table 12-15 Last milestone completed at time of withdrawal: January 1, 1997 through December 31, 2015

Milestone Completed	Projects Withdrawn	Percent
Never Started	173	10.4%
Feasibility Study	620	37.1%
System Impact Study	548	32.8%
Facilities Study	108	6.5%
Interconnection Service Agreement (ISA)	37	2.2%
Wholesale Market Participation Agreement (WMPA)	128	7.7%
Construction Service Agreement (CSA) or beyond	56	3.4%
Total	1,670	100.0%

Table 12-16 shows, by MW, the rate at which projects drop out of the queue as they move through the process, as well as the rate at which projects eventually go into service. Out of 327,280.0 nameplate MW that entered the queue, 41,021.9, 12.5 percent, went into service, while the remaining 286,258.0 MW withdrew at some point. Of the withdrawals, 39.6 percent happened after the feasibility study was completed.

Table 12-14 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

20 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>.

21 See presentation by Dave Egan to the Planning Committee PJM, at <http://www.pjm.com/~/media/committees-groups/committees/pc/20150611/20150611-item-09-queue-status-update.ashx>

22 See Earlier Queue Submittal Task Force at <http://www.pjm.com/committees-and-groups/task-forces/eqstf.aspx>

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

24 "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.

25 See PJM. "Manual 14C: Generation and Transmission Interconnection Facility Construction," Revision 08 (December 20, 2012), p.22.

Table 12-16 Completed (withdrawn or in service) queue MW: January 1, 1997 through December 31, 2015

Milestone Completed	MW in Queue	Percent of Total in Queue	MW Withdrawn	Percent of Total Withdrawn	Percent that Go In Service
Enter Queue	327,280.0	100.0%	27,566.5	9.6%	12.5%
Feasibility Study	299,713.5	91.6%	145,294.4	50.8%	13.7%
System Impact Study	154,419.1	47.2%	94,994.6	33.2%	26.6%
Facilities Study	59,424.6	18.2%	1,000.1	0.3%	69.0%
ISA/WMPA	58,424.5	17.9%	7,408.2	2.6%	70.2%
Construction	51,016.3	15.6%	9,994.4	3.5%	80.4%
In-Service	41,021.9	12.5%	0.0	0.0%	100.0%

Table 12-17 and Table 12-18 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 933 days, or 2.6 years, between entering a queue and going into service. Nuclear and wind projects tend to take longer to go into service averaging 1,468 and 1,474 days. The average time to go into service for all other fuel types is 703 days. For withdrawn projects, there is an average time of 667 days between entering a queue and withdrawing.

Table 12-17 Average project queue times (days): At December 31, 2015

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	1,004	751	21	4,179
In-Service	933	688	1	4,024
Suspended	2,160	830	545	4,149
Under Construction	1,653	991	116	6,380
Withdrawn	667	667	7	4,249

Table 12-18 presents information on the time in the stages of the queue for those projects not yet in service. Of the 658 projects in the queue as of December 31, 2015, 96 had a completed feasibility study and 227 were under construction.

Table 12-18 PJM generation planning summary: At December 31, 2015

Milestone Completed	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Not Started	138	21.0%	714	1,828
Feasibility Study	96	14.6%	764	2,555
Impact Study	89	13.5%	1,274	3,745
Facilities Study	15	2.3%	1,585	3,279
Interconnection Service Agreement (ISA)	24	3.6%	1,502	3,653
Wholesale Market Participation Agreement (WMPA)	3	0.5%	1,067	2,167
Construction Service Agreement (CSA)	11	1.7%	2,663	4,179
Under Construction	227	34.5%	1,653	6,380
Suspended	55	8.4%	2,160	4,149
Total	658	100.0%		

The time it takes to complete a study depends on the backlog and the number of projects in the queue, but not on the size of the project. Table 12-19 shows the number of projects that entered the queue by year. The last two years show an increase in queue entries, primarily by renewable projects (solar, hydro, storage, biomass, wind). Of the 495 projects entered in 2014 and 2015, 314, 63.4 percent, were renewable.

Table 12-19 Number of projects entered in the queue as of December 31, 2015

	Fuel Group			
Year Entered	Nuclear	Renewable	Traditional	Grand Total
1997	2	1	10	13
1998	0	0	18	18
1999	1	5	83	89
2000	2	3	75	80
2001	4	6	81	91
2002	3	14	32	49
2003	1	34	17	52
2004	4	17	32	53
2005	3	77	52	132
2006	9	77	71	157
2007	9	68	142	219
2008	3	114	99	216
2009	10	113	50	173
2010	5	381	55	441
2011	6	264	78	348
2012	2	73	80	155
2013	1	78	72	151
2014	0	122	68	190
2015	0	192	113	305
Grand Total	65	1,639	1,228	2,932

Even though renewable projects comprise the majority of projects entered in the queue, as well as what is currently active in the queue, renewable projects only account for 24.0 percent of the nameplate MW currently active in the queue (Table 12-20).

Table 12-20 Queue details by fuel group: At December 31, 2015

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	10	1.5%	1,826.0	2.1%
Renewable	405	61.6%	20,496.0	24.0%
Traditional	243	36.9%	63,001.1	73.8%
Total	658	100.0%	85,323.1	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. It is clear that the TOs perform the studies.[26] The coordination begins with PJM identifying transmission issues resulting from the generation projects. The TOs perform the studies and provide the mitigation requirements. A facilities study is required only for new generation and significant generation additions and is the study in which the TO is most involved. For a facilities study, the interconnected TO (ITO) and any other affected TOs are required to conduct their own facilities study and provide a summary and results to PJM. PJM compiles these results, along with inputs from the developer, into PJM's models to confirm that the TOs' defined upgrades will resolve the issue. PJM writes the final facilities report, which includes the inputs, a description of the issues to be resolved, and the findings of all contributing TOs.[27]

Of 658 active projects analyzed, the developer and TO are part of the same company for 52 of the projects, or 11,478.2 MW of a total 85,323.1 MW, or 13.5 percent. Where the TO is a vertically integrated company that also owns generation, there is a potential conflict of interest when the TO 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 12-21 is a summary of the number of projects and total MW, by transmission owner parent company, which identifies the number of projects for which the developer and transmission owner are part of the same company. The Dominion Zone has nine related projects which account for 5,902.1 MW, 55.7 percent of the total MW currently in the queue in the Dominion Zone. Of that, 4,296.1 MW (72.8 percent) are natural gas projects, 1,594.0 MW are nuclear, and 12 MW are wind. Renewable projects comprise 3,461.9 MW, 73.8 percent, of unrelated projects in the queue in the Dominion Zone. In contrast, the AEP Zone has 12 related projects, but they account for only 2.5 percent of its total MW currently in the queue.

Table 12-21 Summary of project developer relationship to TO parent company

	Number of Projects			Total MW		
Parent Company	Related	Unrelated	Percent Related	Related	Unrelated	Percent Related
AEP	12	82	12.8%	370.2	14,301.0	2.5%
AES	3	5	37.5%	34.5	325.3	9.6%
DLCO	0	2	0.0%	0.0	225.0	0.0%
Dominion	9	65	12.2%	5,902.1	4,689.2	55.7%
Duke	1	6	14.3%	50.0	766.4	6.1%
Exelon	15	96	13.5%	2,646.0	10,852.6	19.6%
First Energy	1	210	0.5%	1,710.0	24,968.8	6.4%
Pepco	0	85	0.0%	0.0	7,009.5	0.0%
PPL	0	30	0.0%	0.0	7,768.3	0.0%
PSEG	11	24	31.4%	765.4	1,788.8	30.0%
EKPC	0	1	0.0%	0.0	1,150.0	0.0%
Total	52	606	7.9%	11,478.2	73,844.9	13.5%

These projects are shown by fuel type in Table 12-22. Natural gas generators comprise 66.4 percent of the total related MW in this table. Developers of coal and nuclear projects are almost entirely related to the TO, with 93.6 percent and 100.0 percent of MW. Developers are related to the TO for 12.6 percent of the natural gas project MW in the queue, 8.1 percent of the storage project MW, and 11.0 percent of the hydro project MW. All other fuel types projects have no more than 1.0 percent of MW in development related to the TO.

26 See PJM, OATT, Part VI, § 210
27 See PJM. "Manual 14A: "Generation and Transmission Interconnection Process," Revision 17, (January 22, 2015),<http://www.pjm.com/documents/manuals.aspx>

Table 12-22 Developer-transmission owner relationship by fuel type

				MW by Fuel Type											
Parent Company	Transmission Owner	Related to Developer	Number of Projects	Biomass	Coal	Diesel	Hydro	Landfill Gas	Natural Gas	Nuclear	Oil	Solar	Storage	Wind	Total MW
AEP	AEP	Related	12	0.0	83.0	0.0	34.0	0.0	137.0	102.0	0.0	12.2	2.0	0.0	370.2
		Unrelated	82	0.0	128.0	0.0	100.0	13.0	7,239.0	0.0	0.0	107.0	112.0	6,602.0	14,301.0
AES	DAY	Related	3	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5	20.0	0.0	34.5
		Unrelated	5	1.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.4	0.0	300.0	325.3
DLCO	DLCO	Unrelated	2	0.0	0.0	0.0	0.0	0.0	205.0	0.0	0.0	0.0	20.0	0.0	225.0
Dominion	Dominion	Related	9	0.0	0.0	0.0	0.0	0.0	4,296.1	1,594.0	0.0	0.0	0.0	12.0	5,902.1
		Unrelated	65	62.5	0.0	0.0	0.0	14.0	1,227.3	0.0	0.0	1,891.3	34.0	1,460.1	4,689.2
Duke	DEOK	Related	1	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0
		Unrelated	6	0.0	0.0	0.0	112.0	6.4	513.0	0.0	0.0	125.0	10.0	0.0	766.4
Exelon	BGE	Related	2	0.0	0.0	0.0	0.0	0.0	256.0	0.0	0.0	20.0	0.0	0.0	276.0
		Unrelated	28	0.0	0.0	25.0	0.4	4.0	1.3	0.0	132.0	3.1	20.1	0.0	185.9
	ComEd	Related	4	0.0	0.0	0.0	0.0	0.0	0.0	80.0	0.0	0.0	0.0	0.0	80.0
		Unrelated	55	0.0	0.0	0.0	22.7	46.1	5,578.9	0.0	0.0	0.0	111.1	3,472.5	9,231.3
	PECO	Related	9	0.0	0.0	0.0	0.0	0.0	2,200.0	50.0	0.0	0.0	40.0	0.0	2,290.0
		Unrelated	13	0.0	0.0	6.1	0.0	2.0	1,426.5	0.0	0.0	0.0	0.8	0.0	1,435.4
First Energy	APS	Related	1	0.0	1,710.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,710.0
		Unrelated	71	0.0	0.0	0.0	0.0	15.2	4,469.5	0.0	0.0	354.8	73.0	1,251.8	6,164.3
	ATSI	Unrelated	19	0.0	0.0	0.0	0.0	5.6	6,006.7	0.0	0.0	0.0	32.5	518.0	6,562.8
	JCPL	Unrelated	76	0.0	0.0	0.0	0.0	0.0	3,376.8	0.0	0.0	482.6	180.0	0.0	4,039.4
	Met-Ed	Unrelated	5	0.0	0.0	0.0	0.0	0.0	2,345.6	0.0	0.0	3.0	0.0	0.0	2,348.6
	PENELEC	Unrelated	39	0.0	0.0	0.0	40.0	0.0	5,267.0	0.0	0.0	13.5	40.0	493.3	5,853.8
Pepco	AECO	Unrelated	25	0.0	0.0	0.0	0.0	0.0	1,987.0	0.0	0.0	60.2	21.0	373.0	2,441.2
	DPL	Unrelated	52	0.0	0.0	0.0	0.0	2.0	749.0	0.0	0.0	405.1	20.0	749.6	1,925.7
	Pepco	Unrelated	8	0.0	0.0	0.0	0.0	0.0	2,642.6	0.0	0.0	0.0	0.0	0.0	2,642.6
PPL	PPL	Unrelated	30	16.0	0.0	0.0	0.0	5.0	7,234.8	0.0	0.0	16.0	30.0	466.5	7,768.3
PSEG	PSEG	Related	11	0.0	24.0	0.0	0.0	0.0	738.0	0.0	0.0	3.4	0.0	0.0	765.4
		Unrelated	24	0.0	0.0	0.0	0.0	0.0	1,670.6	0.0	0.0	116.2	2.0	0.0	1,788.8
EKPC	EKPC	Unrelated	1	0.0	0.0	0.0	0.0	0.0	1,150.0	0.0	0.0	0.0	0.0	0.0	1,150.0
Total		Related	52	0.0	1,879.0	0.0	34.0	0.0	7,627.1	1,826.0	0.0	38.1	62.0	12.0	11,478.2
		Unrelated	606	80.4	128.0	31.1	275.1	113.3	53,090.6	0.0	132.0	3,601.2	706.5	15,686.8	73,844.9

Regional Transmission Expansion Plan (RTEP)

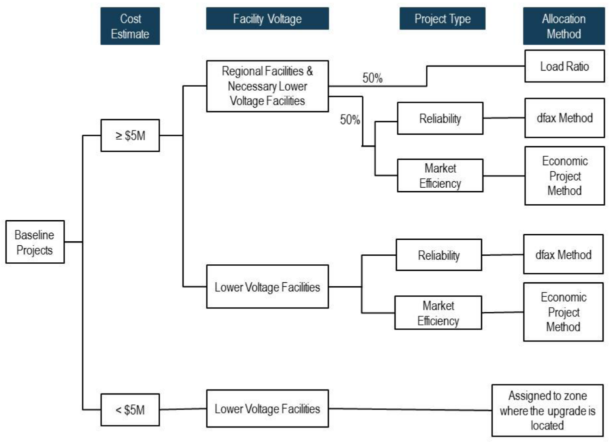
PJM's Transmission Expansion Advisory Committee (TEAC), made up of PJM staff, is responsible for the Regional Transmission Expansion Plan (RTEP).[28] Transmission upgrades can be divided into three categories: network, supplemental, and baseline. Network upgrades are initiated by generation queue projects and are funded by the developers of the generation projects. Supplemental upgrades are initiated and funded by the TOs. Baseline upgrades are initiated by the TEAC to resolve market efficiency and reliability criteria violations not addressed in other ways. Per FERC Order 1000, the TEAC solicits proposals via fixed proposal windows to address these needs. The TEAC evaluates the proposals and recommends proposals to the PJM Board of Managers for approval. All approved baseline projects are added to the RTEP via amendments to the tariff. Retired generators are included in this analysis for one year after their retirement to reflect the ownership of CIRs.

RTEP Cost Allocation

The costs of RTEP baseline projects are allocated to all transmission owners, based on the size of the project, the facility voltage, and whether the project addresses a reliability issue or market efficiency. In addition, the allocation methods attempt to distribute the costs proportionally with respect to who will benefit from the upgrade. The allocation rules are summarized in Figure 12-3.

28 See PJM. "Manual 14B: PJM Region Transmission Planning Process," Revision 30 (February 26, 2015), Section 2, p.14.

Figure 12-3 RTEP cost allocation rules



For reliability projects, upgrade costs are allocated based on distribution factors (dfax). The distribution factors used in the current allocation method are a measure of the use of the transmission upgrade by zonal loads and by merchant transmission facilities, based on power flow analysis. Under this allocation method (solutions based method), a zone with a distribution factor less than 0.01 is not allocated any costs regardless of its load on the line.[29] This approach to cost allocation replaced the earlier method which was based on distribution factors as a measure of contributions to the reasons for the transmission upgrade.[30]

In 2015, the Board approved four separate amendments to the RTEP. The first was a result of a proposal window opened in 2014 to address reliability criteria violations including baseline N-1 voltage, N-1-1 voltage, light load reliability criteria (thermal & voltage), and local TO criteria. The second included the Artificial Island projects and some adjustments to existing upgrade projects.[31] The last two were to address the two RTEP proposal windows opened in 2015, one for baseline N-1, generation deliverability and common mode outage, N-1-1, and load deliverability and the other for light load analysis and 2020 TO criteria.[32,33] Table 12-23 shows a summary of the all of the new baseline upgrade costs in 2015 for each TO, as well as how those costs were allocated.[34]

Table 12-23 2015 Board approved new baseline upgrades by transmission owner and allocations

Baseline Upgrades ($ million)						
Transmission Owner	17-Feb-15	29-Jul-15	15-Oct-15	15-Dec-15	Total Approved Upgrades	Total Allocated Costs
AECO	0.0	0.0	0.0	0.0	0.0	3.5
AEP	262.7	29.2	93.1	0.0	385.0	513.0
AP	61.2	12.2	0.1	0.0	73.5	35.1
ATSI	0.0	16.7	0.0	0.0	16.7	33.6
BGE	0.0	0.0	0.0	0.0	0.0	12.6
ComEd	0.7	24.7	15.0	0.0	40.4	48.6
ConEd	0.0	0.0	0.0	0.0	0.0	1.1
DAY	0.0	0.0	0.0	0.0	0.0	4.7
DEOK	0.0	6.8	0.0	0.0	6.8	14.5
DLCO	0.0	12.9	0.0	0.0	12.9	5.7
Dominion	213.0	468.6	287.4	0.0	969.0	857.9
DPL	0.0	2.4	0.0	2.5	4.9	255.4
ECP	0.0	0.0	0.0	0.0	0.0	0.5
EKPC	2.1	2.7	0.5	0.0	5.2	9.7
HTP	0.0	0.0	0.0	0.0	0.0	0.5
JCPL	19.0	1.5	6.5	1.0	28.0	34.5
Met-Ed	1.0	13.9	0.4	0.0	15.2	13.7
Neptune	0.0	0.0	0.0	0.0	0.0	1.0
NTD	0.0	0.0	0.0	129.6	129.6	0.0
PECO	1.5	9.7	0.3	0.0	11.5	13.4
PENELEC	5.8	24.1	0.0	0.0	29.8	34.0
Pepco	0.0	0.0	0.0	0.0	0.0	38.6
PPL	0.8	4.2	0.0	0.0	5.0	15.2
PSEG	15.6	4.5	157.7	142.4	320.2	165.9
RECO	0.0	0.0	0.0	0.0	0.0	0.5
TranSource	59.5	0.0	0.0	0.0	59.5	0.0
Total	642.8	634.0	561.0	275.5	2,113.3	2,113.3

Cost Allocation Issues

The RTEP Baseline Upgrade filings, ER14-972-000 on January 10, 2014, and ER14-1485-000 on March 13, 2014, represented the first time the new allocation rules were used. They resulted in approximately $1.5 billion in additional baseline transmission enhancements and expansions. PJM approved additional RTEP upgrades (Docket Nos. ER15-2562 and ER15-2563) on July 29, 2015.

29 OATT, Schedule 12(b)(iii). (p.595).

30 See *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 (2013).

31 Artificial Island is an area in the PSEG Zone in southern New Jersey that includes nuclear units at Salem and at Hope Creek. The projects, assigned to TO PSEG, TO PHI, and merchant TO LS Power will address stability issues, operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations.

32 See "PJM RTEP – 2015 RTEP Proposal Window #1 Problem Statement & Requirements Document," June 19, 2015 at <http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/2015-rtep-window-1-problem-statement-and-requirements.ashx>.

33 See "PJM RTEP – 2015 RTEP Proposal Window #1 Problem Statement & Requirements Document," August 5, 2015 at <http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/2015-rtep-window-2-problem-statement-and-requirements-document.ashx>.

34 The totals will not match the corresponding whitepapers published by PJM because cost estimates are adjusted frequently and these data show the most accurate current estimates.

In response to complaints about the cost allocations in these filings, on November 24, 2015, FERC accepted, and immediately suspended for five months, both of the July 29, 2015 filings. FERC concluded that "the proposed Tariff amendments have not been shown to be just and reasonable."[35]

FERC ordered a technical conference, which took place on January 12, 2016, to address the complaints in proceedings EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island). FERC identified two main discussion points: Whether there is "a definable category of reliability projects within PJM for which the solution-based dfax cost allocation method may not be just and reasonable" and whether there is "an alternative just and reasonable ex ante cost allocation method that could be established for any such category of projects."[36]

The issues identified in the complaints and at the technical conference include: whether the solutions based allocation method is appropriate for upgrades not related to transmission overload issues; whether the solutions based allocation method correctly identifies all the beneficiaries of the upgrades; whether it is reasonable to allocate a level of costs to a merchant transmission project that could force bankruptcy; and whether the significant shifts in allocation that result from use of the .01 distribution factor cutoff are appropriate.

The MMU recognizes that the allocation issues are difficult. Nonetheless the allocation methods affect the efficiency of the markets and the incentives for merchant transmission owners to compete to build new transmission. It appears that use of the arbitrary .01 distribution factor cutoff can result in large shifts in cost allocation. It also appears that the if the intent of the use of the .01 cutoff is to help eliminate small, arbitrary cost allocations to geographically distant areas, another approach would be to add a threshold for a minimum usage impact on the line. The MMU recommends consideration of changing the minimum distribution factor in the allocation from .01 to .00 and adding a threshold minimum impact on the load on the line.

TranSource

TranSource LLC filed a complaint against PJM on June 23, 2015, amended February 10, 2016, seeking work papers explaining how PJM performed System Impact Studies (SIS) for three TranSource transmission projects.[37] TranSource complains, in addition, that PJM "fail[ed] to provide TranSource with open access on a nondiscriminatory basis to the PJM transmission planning process and to Auction Revenue Rights (ARR) associated with transmission upgrades" and "violated its requirement to provide TranSource with a transparent, replicable process for evaluating transmission upgrade requests."[38] PJM responded that it has provided all work papers relevant to the SIS and objects to the complaint on procedural grounds.[39] On September 24, 2015, the Commission issued an order establishing hearing and settlement judge procedures.[40] The MMU is participating in this process.

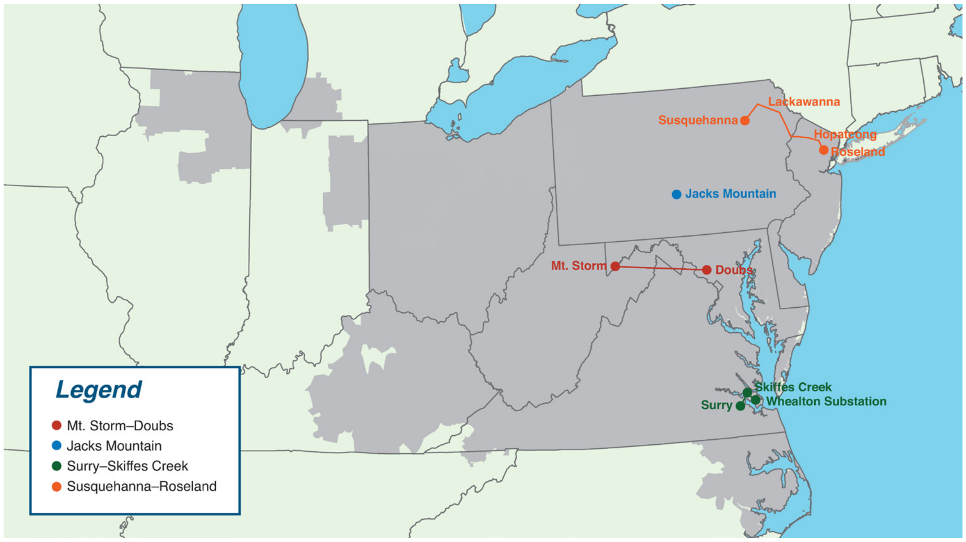
Backbone Facilities

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. Designated backbone projects in 2015 included Mount Storm-Doubs, Jacks Mountain, Susquehanna-Roseland, and Surry Skiffes Creek 500kV. Figure 12-4 shows the location of these four projects. Surry Skiffes Creek 500kV is the only remaining active backbone project.

35 153 FERC ¶ 61,245 (November 24, 2015).
36 "Supplemental Notice of Technical Conference re PJM Interconnection, LLC et al under ER15-2562 et al.," Docket No. E15-95-000 (December 30, 2015).

37 TranSource Complaint, Amended and Restated Complaint and Request for Fast Track Processing of TranSource, LLC, FERC Docket No. EL15-79-000.
38 *Id.* at 1–2.
39 See Motion to Dismiss Complaint and Answer to Complaint Submitted on Behalf of PJM Interconnection, L.L.C., Docket No. EL15-79-000 (July 10, 2015).
40 152 FERC ¶ 61,229.

Figure 12-4 PJM Backbone Projects



Two of these projects, Mount Storm-Doubs and Susquehanna-Roseland, were completed in 2015 and are currently in service. The Jacks Mountain backbone project has been cancelled. It was initiated to resolve voltage problems for load deliverability starting June 1, 2017.

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. The initial project includes 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. PJM's required in service date for the 500kv portion was June 1, 2015. This project has been delayed by legal challenges. BASF Corporation raised environmental concerns with the siting and the design. James City County and James River Association (JCC) argued that the switching station is not part of the transmission line and therefore should be subject to local zoning ordinances. In an April 16, 2015, ruling, the Supreme Court of Virginia rejected BASF's claim but agreed with JCC.[41] On April 30, 2015, Dominion filed a petition for rehearing, which was rejected, and the case was remanded to the State Corporation Commission (SCC). The SCC issued an order on June 5, 2015, stressing the need for this project to be completed, extending the completion date to December 31, 2015.[42] The SCC issued another order on December 4, 2015, temporarily suspending this updated completion date, pending the Army Corps of Engineers' (ACE) issuance of a construction permit.[43] The ACE is currently studying the effects of the project as currently proposed, as well as an alternative approach. The JCC Board will vote on the final action in January, 2016 or later, at which point an energization date can be established.[44]

Transmission Facility Outages

Scheduling Transmission Facility Outage Requests

A transmission facility is designated as reportable by PJM if a change in its status can affect a transmission constraint on any Monitored Transmission Facility or could impede free flowing ties within the PJM RTO and/or adjacent areas.[45] 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.[46]

41 BASF Corporation v SCC, et al., Record No. 141009 et al.

42 See Commonwealth of Virginia State Corporation Commission Order in Case No. PUE-2012-00029, June 5, 2015 at <https://www.dom.com/library/domcom/pdfs/electric-transmission/surry-skiffes-creek/scc-order-060515.pdf>.

43 See Commonwealth of Virginia State Corporation Commission Order in Case No. PUE-2012-00029, December 4, 2015 at <https://www.dom.com/library/domcom/pdfs/electric-transmission/surry-skiffes-creek/due-date-order-120415.pdf?la=en>.

44 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>.

45 If a transmission facility is not modeled in the PJM EMS or the facility is not expected to significantly impact PJM system security or congestion management, it is not reportable. See PJM. "Manual 3A: Energy Management System (EMS) Model Updates and Quality Assurance (QA), Revision 10 (June 25, 2015).

46 See PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015), p.57.

Transmission outages have significant impacts on PJM markets. There are impacts on FTR auctions, on congestion, and on expected market outcomes in the day-ahead and real-time markets. It is important for the efficient functioning of the markets that there be clear, enforceable rules governing transmission outages.

Transmission 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.[47] Table 12-24 shows that 79.2 percent of the requested outages were planned for less than or equal to five days and 4.9 percent of requested outages were planned for greater than 30 days in 2015. All of the outage data in this section are for outages scheduled to occur in 2014 and 2015, regardless of when they were initially submitted.[48]

Table 12-24 Transmission facility outage request summary by planned duration: 2014 and 2015

	2014		2015	
Planned Duration (Days)	Outage Requests	Percent	Outage Requests	Percent
<=5	15,645	79.8%	15,521	79.2%
>5 & <=30	2,917	14.9%	3,117	15.9%
>30	1,052	5.4%	953	4.9%
Total	19,614	100.0%	19,591	100.0%

After receiving a transmission facility outage request from a TO, PJM assigns a received status to the request based on its submission date, outage planned starting and ending date, and outage planned duration. The received status can be on time, late or past deadline, as defined in Table 12-25.[49]

The purpose of the rules defined in Table 12-25 is to require the TOs to submit transmission facility outages prior to the Financial Transmission Right (FTR) auctions so that market participants have complete information about market conditions on which to base their FTR bids and so that PJM can accurately model market conditions.[50]

Table 12-25 PJM transmission facility outage request received status definition

Planned Duration (Days)	Ticket Submission Date	Received 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 of the outage	On Time
	After or on the earlier of 1) February 1st, 2) the 1st of the month six months prior to the starting month of the outage	Late
	After 8:00AM three days prior to the outage	Past Deadline

Table 12-26 shows a summary of requests by received status. In 2015, 49.1 percent of outage requests received were late.

Table 12-26 Transmission facility outage request summary by received status: 2014 and 2015

	2014				2015			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	8,124	7,521	15,645	48.1%	8,075	7,446	15,521	48.0%
>5 & <=30	1,482	1,435	2,917	49.2%	1,527	1,590	3,117	51.0%
>30	449	603	1,052	57.3%	377	576	953	60.4%
Total	10,055	9,559	19,614	48.7%	9,979	9,612	19,591	49.1%

Once received, PJM processes outage requests in priority order: emergency transmission outage request; transmission outage requests submitted on time; and transmission outage request submitted late. PJM retains the right to deny all transmission outage requests that are submitted past the relevant deadline unless the request is an emergency.[51]

Outages with emergency status will be approved even if submitted past the relevant deadline after PJM determines that the outage does not result in Emergency Procedures. PJM cancels or withholds approval of any outage that results in Emergency Procedures.[52] Table 12-27 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in 2015,

47 See PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015), p.58.
48 The hotline tickets, EMS tripping tickets or test outage tickets were excluded. We only included all the transmission outage tickets submitted by PJM internal companies which are currently active.
49 See PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015), p.58 and p.59.
50 See "Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).
51 PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015), p. 69.
52 PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015), p. 67 and p.68.

13.3 percent were for emergency outages. Of all outage requests scheduled to occur in 2014, 14.1 percent were for emergency outages.

Table 12-27 Transmission facility outage request summary by emergency: 2014 and 2015

	2014				2015			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	2,249	13,396	15,645	14.4%	2,103	13,418	15,521	13.5%
>5 & <=30	370	2,547	2,917	12.7%	402	2,715	3,117	12.9%
>30	143	909	1,052	13.6%	99	854	953	10.4%
Total	2,762	16,852	19,614	14.1%	2,604	16,987	19,591	13.3%

PJM will approve all transmission outage requests that are submitted on time and do not jeopardize the reliability of the PJM system. PJM will approve all transmission outage requests that are submitted late and do not cause congestion on the PJM system and do not jeopardize the reliability of the PJM system.

Table 12-28 Transmission facility outage request summary by congestion: 2014 and 2015

	2014				2015			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	1,492	14,153	15,645	9.5%	1,428	14,093	15,521	9.2%
>5 & <=30	307	2,610	2,917	10.5%	360	2,757	3,117	11.5%
>30	113	939	1,052	10.7%	101	852	953	10.6%
Total	1,912	17,702	19,614	9.7%	1,889	17,702	19,591	9.6%

Table 12-29 Transmission facility outage requests that by received status, congestion and emergency: 2014 and 2015

Submission Status		2014 Congestion Expected	2014 No Congestion Expected	2014 Total	2014 Percent Congestion	2015 Congestion Expected	2015 No Congestion Expected	2015 Total	2015 Percent Congestion
Late	Emergency	97	2,650	2,747	3.5%	113	2,474	2,587	4.4%
	Non Emergency	374	6,438	6,812	5.5%	342	6,683	7,025	4.9%
On Time	Emergency	1	14	15	6.7%	3	14	17	17.6%
	Non Emergency	1,440	8,600	10,040	14.3%	1,431	8,531	9,962	14.4%
Total		1,912	17,702	19,614	9.7%	1,889	17,702	19,591	9.6%

After PJM determines that a late request may cause congestion, PJM informs the Transmission Owner of solutions available to eliminate the congestion. For example, if a generator planned or maintenance outage request is contributing to the congestion, PJM can request that the Generation Owner defer the outage. If no solutions are available, PJM may require the Transmission Owner to reschedule or cancel the outage. Table 12-28 is a summary of outage requests by congestion status. Of all outage requests submitted in 2015, 9.6 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 4.1 percent (78 out of 1,889) were denied by PJM in 2015 (Table 12-30).

Table 12-29 shows the outage requests summary by received status, congestion status and emergency status. In 2015, 73.1 percent of late requests were non-emergency outages while 4.9 percent of late non-emergency outage requests were expected to cause congestion in 2015.

Once PJM processes an outage request, the outage request is labelled as submitted, received, denied, approved, cancelled by company, revised, active or complete according to the processed stage of a request.[53] Table 12-30 shows the detailed process status for outage requests only for the outage requests that are expected to cause congestion. All process status categories except cancelled, complete or denied are in the In Process category in Table 12-30. Table 12-30 shows that 72.8 (249 out of 342) percent of late, non-emergency, outage requests which were expected to cause congestion were approved and completed and 4.1 percent (78 out of 1,889) of the outage requests which were expected to cause congestion were denied in 2015.

53 See PJM. "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (November 1, 2015).

Table 12-30 Transmission facility outage requests that might cause congestion status summary: 2014 and 2015

		2014						2015					
Submission Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	4	92	1	0	97	94.8%	12	100	0	1	113	88.5%
	Non Emergency	77	257	1	39	374	68.7%	65	249	2	26	342	72.8%
On Time	Emergency	1	0	0	0	1	0.0%	0	3	0	0	3	100.0%
	Non Emergency	322	1,038	2	78	1,440	72.1%	384	994	2	51	1,431	69.5%
Total		404	1,387	4	117	1,912	72.5%	461	1,346	4	78	1,889	71.3%

There are clear rules defined for assigning on time or late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[54] However, the on time or late status only affects the priority that PJM assigns for processing the outage request. Many (72.8 percent) non-emergency, expected to cause congestion, late transmission outages were approved and completed. The expected impact on congestion is the basis for PJM's treatment of late outage requests. But there is no rule or clear definition of this congestion analysis in the PJM Manuals. The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review.

Rescheduling Transmission Facility Outage Requests

Table 12-31 Rescheduled and cancelled transmission outage request summary: 2014 and 2015

	2014					2015				
Days	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled
<=5	15,645	1,913	12.2%	2,127	13.6%	15,523	1,788	11.5%	2,028	13.1%
>5 & <=30	2,917	1,435	49.2%	197	6.8%	3,117	1,472	47.2%	203	6.5%
>30	1,052	648	61.6%	51	4.8%	953	544	57.1%	63	6.6%
Total	19,614	3,996	20.4%	2,375	12.1%	19,593	3,804	19.4%	2,294	11.7%

A TO can reschedule or cancel an outage after initial submission. Table 12-31 is a summary of all the outage requests planned for 2014 and 2015 which were approved and then cancelled or rescheduled by TOs at least once. If an outage request was submitted, approved and subsequently rescheduled at least once, the outage request will be counted as Approved and Rescheduled. If an outage request was submitted, approved and subsequently cancelled at least once, the outage request will be counted as Approved and Cancelled. In 2015, 19.4 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 11.7 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs.

If a requested outage is determined to be late and TO reschedules the outage, the outage will be revaluated by PJM again as on time or late.

A transmission outage ticket with a duration of five days or less with an on time status can retain its on time status if the outage is rescheduled within the original scheduled month.[55] This rule allows a TO to reschedule within the same month with very little notice.

54 OATT Attachment K Appendix § 1.9.2 (Outage Scheduling).

55 PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015), p. 63.

A transmission outage ticket with a duration exceeding five days with an on time status can retain its on time status if the outage is rescheduled to a future month, and the revision is submitted by the first of the month prior to the revised month in which the outage will occur.[56] This rescheduling rule is much less strict than the rule that applies to the first submission of outage requests with similar duration. When first submitted, the outage request with a duration exceeding five days needs to be submitted before the first of the month six months prior to the month in which the outage was expected to occur.

The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages.

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-25) define a transmission outage request as on time or late based on the planned outage duration and the time of submission. The rule has stricter submission requirements for transmission outage requests planned for longer than 30 days. In order to avoid the stricter submission requirement, some transmission owners divided the duration of outage requests longer than 30 days into shorter segments for the same equipment and submitted one request for each segment. The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. Table 12-32 shows that there were 11,274 transmission equipment planned outages in 2015, of which 855 were planned outages longer than 30 days, and of which 188 or 1.7 percent were scheduled longer than 30 days if the duration of the outages were combined for the same equipment. The duration of those outages could potentially be longer than 30 days, however were divided into shorter periods by transmission owners.

56 PJM. "Manual 3: Transmission Operations," Revision 48 (December 1, 2015), p. 64.

Table 12-32 Transmission outage summary: 2014 and 2015

		2014		2015	
Duration	Divided into Shorter Periods	Number of Outages	Percent	Number of Outages	Percent
> 30 Days	No	923	8.3%	855	7.6%
	Yes	193	1.7%	188	1.7%
<= 30 Days		10,047	90.0%	10,231	90.7%
Total		11,163	100.0%	11,274	100.0%

Table 12-33 shows the details of potentially long duration (> 30 days) outages when combining the duration of the outages for the same equipment. The actual duration of scheduled outages would be longer than 30 days if the duration of the outages were combined for the same equipment within a period of days. In 2015, there would have been five outages with a combined duration longer than 30 days that were instead scheduled to occur as shorter outages within a period of less than or equal to 31 days. In 2015, there would have been 150 outages with a combined duration longer than 30 days that were instead scheduled to occur as shorter outages within a period of more than 92 days.

Table 12-33 Summary of potentially long duration (> 30 days) outages: 2014 and 2015

	2014		2015	
Days	Number of Outages	Percent	Number of Outages	Percent
<=31	5	2.6%	5	2.7%
>31 & <=62	21	10.9%	13	6.9%
>62 and <=92	20	10.4%	20	10.6%
>=92	147	76.2%	150	79.8%
Total	193	100.0%	188	100.0%

Transmission Facility Outage Analysis for the FTR Market

Transmission facility outages affect the price and quantity outcomes of FTR auctions. The purpose of the rules is to ensure that outages are known with enough lead time prior to FTR auctions both so that market participants can understand market conditions and so that PJM can accurately model market conditions. Outage requests must be submitted according to rules based on planned outage duration (Table 12-25). The rules defining when an outage is late are based on the timing of FTR auctions. When an outage request is submitted late, the outage will be marked as late and may be denied if it is expected to cause congestion. Table 12-37 shows that 637 outage requests with a duration of two weeks or longer but shorter than two months were late, and only four of them were denied by

PJM. Table 12-37 also shows that 189 outage requests with a duration of two months or longer were late and none of them were denied by PJM in the 2015 to 2016 planning year.

There are Long Term, Annual and Monthly Balance of Planning Period auctions in the FTR market. When modeling transmission outages in the annual ARR allocation and FTR auction, PJM does not consider outages with planned durations shorter than two weeks, does consider some outages with planned duration longer than two weeks but shorter than two months, and does consider all outages with planned duration longer than or equal to two months. PJM posts an FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[57]

Table 12-34 shows that 88.3 percent of the outage requests for outages expected to occur during the planning period 2015 to 2016 had a planned duration of less than two weeks and that 44.7 (6,800 out of 15,225) percent of all outage requests for the planning period were submitted late according to outage submission rules.

Table 12-35 shows outage requests summary by emergency status. Of all outage requests for outages expected to occur in the 2015 to 2016 planning year and submitted late, 74.1 percent were for non-emergency outages.

PJM analyzes expected congestion for both on time and late outage requests. A late outage request may be denied or cancelled if it is expected to cause congestion. Table 12-36 shows a summary of requests by expected congestion and received status. Overall, 4.7 percent of all outage requests for outages expected to occur in the 2015 to 2016 planning year and submitted late were requests that were expected to cause congestion.

Table 12-34 Transmission facility outage requests by received status: Planning periods 2014 to 2015 and 2015 to 2016

	2014/2015				2015/2016			
Planned Duration	On Time	Late	Total	Percent	On Time	Late	Total	Percent
<2 weeks	9,307	8,383	17,690	88.7%	7,476	5,974	13,450	88.3%
>=2 weeks & <2 months	844	896	1,740	8.7%	807	637	1,444	9.5%
>=2 months	201	316	517	2.6%	142	189	331	2.2%
Total	10,352	9,595	19,947	100.0%	8,425	6,800	15,225	100.0%

Table 12-35 Transmission facility outage requests by received status and emergency: Planning periods 2014 to 2015 and 2015 to 2016

		2014/2015				2015/2016			
	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	13	9,294	9,307	99.9%	16	7,460	7,476	99.8%
	>=2 weeks & <2 months	0	844	844	100.0%	2	805	807	99.8%
	>=2 months	0	201	201	100.0%	0	142	142	100.0%
	Total	13	10,339	10,352	99.9%	18	8,407	8,425	99.8%
Late	<2 weeks	2,370	6,013	8,383	71.7%	1,623	4,351	5,974	72.8%
	>=2 weeks & <2 months	169	727	896	81.1%	107	530	637	83.2%
	>=2 months	64	252	316	79.7%	31	158	189	83.6%
	Total	2,603	6,992	9,595	72.9%	1,761	5,039	6,800	74.1%

57 PJM Financial Transmission Rights, "Annual ARR Allocation and FTR Auction Transmission outage Modeling," <http://www.pjm.com/~/media/markets-ops/ftr/annual-ftr-auction/2015-2016/2015-2016-annual-outage-modeling.ashx> (April 1, 2015).

Table 12-36 Transmission facility outage requests by submission status and congestion: Planning periods 2014 to 2015 and 2015 to 2016

		2014/2015				2015/2016			
	Planned Duration	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
On Time	<2 weeks	1,340	7,967	9,307	14.4%	933	6,543	7,476	12.5%
	>=2 weeks & <2 months	168	676	844	19.9%	160	647	807	19.8%
	>=2 months	38	163	201	18.9%	33	109	142	23.2%
	Total	1,546	8,806	10,352	14.9%	1,126	7,299	8,425	13.4%
Late	<2 weeks	447	7,936	8,383	5.3%	280	5,694	5,974	4.7%
	>=2 weeks & <2 months	45	851	896	5.0%	34	603	637	5.3%
	>=2 months	9	307	316	2.8%	8	181	189	4.2%
	Total	501	9,094	9,595	5.2%	322	6,478	6,800	4.7%

Table 12-37 shows that 67.0 percent of late outage requests with a duration of two weeks or longer but shorter than two months were completed, 0.6 percent were denied by PJM and 5.5 percent of late outage requests with a duration of two weeks or longer but shorter than two months were approved or active in the 2015 to 2016 planning year. The table also shows that 56.6 percent of late outage requests with duration of two months or longer were completed, none of them were denied, and 25.9 percent were approved and active in the 2015 to 2016 planning year.

Table 12-38 shows that there were 637 outage requests with a duration of two weeks or longer but shorter than two months submitted late, of which 32 were non-emergency and expected to cause congestion in the 2015 to 2016 planning year. Of the 32 such requests, 24 were approved. For the outages planned for two months or longer, there were 331 total outages, of which 189 requests were late. Of the late requests, seven outages that were non-emergency and expected to cause congestion were all approved.

Table 12-37 Transmission facility outage requests by received status and processed status: Planning periods 2014 to 2015 and 2015 to 2016

		2014/2015				2015/2016			
Planned Duration	Processed Status	On Time	Percent	Late	Percent	On Time	Percent	Late	Percent
<2 weeks	In Progress	21	0.2%	149	1.8%	2,180	29.2%	418	7.0%
	Denied	106	1.1%	98	1.2%	55	0.7%	44	0.7%
	Approved	0	0.0%	0	0.0%	7	0.1%	26	0.4%
	Cancelled by Company	2,762	29.7%	1,205	14.4%	1,707	22.8%	715	12.0%
	Revised	0	0.0%	0	0.0%	33	0.4%	2	0.0%
	Active	0	0.0%	0	0.0%	32	0.4%	43	0.7%
	Completed	6,418	69.0%	6,931	82.7%	3,462	46.3%	4,726	79.1%
Total Submission		9,307	100.0%	8,383	100.0%	7,476	100.0%	5,974	100.0%
>=2 weeks & <2 months	In Progress	1	0.1%	9	1.0%	259	32.1%	105	16.5%
	Denied	0	0.0%	4	0.4%	0	0.0%	4	0.6%
	Approved	0	0.0%	0	0.0%	0	0.0%	1	0.2%
	Cancelled by Company	199	23.6%	106	11.8%	183	22.7%	63	9.9%
	Revised	0	0.0%	0	0.0%	8	1.0%	3	0.5%
	Active	0	0.0%	0	0.0%	22	2.7%	34	5.3%
	Completed	644	76.3%	777	86.7%	335	41.5%	427	67.0%
Total Submission		844	100.0%	896	100.0%	807	100.0%	637	100.0%
>=2 months	In Progress	0	0.0%	7	2.2%	20	14.1%	19	10.1%
	Denied	0	0.0%	0	0.0%	0	0.0%	0	0.0%
	Approved	0	0.0%	0	0.0%	1	0.7%	0	0.0%
	Cancelled by Company	42	20.9%	31	9.8%	30	21.1%	14	7.4%
	Revised	0	0.0%	0	0.0%	1	0.7%	0	0.0%
	Active	1	0.5%	2	0.6%	24	16.9%	49	25.9%
	Completed	158	78.6%	276	87.3%	66	46.5%	107	56.6%
Total Submission		201	100.0%	316	100.0%	142	100.0%	189	100.0%

Table 12-38 Transmission facility outage requests by received status, processed status, emergency and congestion: Planning periods 2014 to 2015 and 2015 to 2016

		2014/2015						2015/2016					
		On Time			Late			On Time			Late		
Planned Duration	Processed Status	Non Emergency and Congestion Expected	Total	Percent	Non Emergency and Congestion Expected	Total	Percent	Non Emergency and Congestion Expected	Total	Percent	Non Emergency and Congestion Expected	Total	Percent
<2 weeks	In Progress	2	21	9.5%	3	149	2.0%	200	2,180	9.2%	16	418	3.8%
	Denied	70	106	66.0%	39	98	39.8%	24	55	43.6%	13	44	29.5%
	Approved	0	0	0.0%	0	0	0.0%	2	7	28.6%	2	26	7.7%
	Cancelled by Company	363	2,762	13.1%	75	1,205	6.2%	214	1,707	12.5%	42	715	5.9%
	Revised	0	0	0.0%	0	0	0.0%	3	33	9.1%	0	2	0.0%
	Active	0	0	0.0%	0	0	0.0%	5	32	15.6%	1	43	2.3%
	Completed	904	6,418	14.1%	224	6,931	3.2%	482	3,462	13.9%	135	4,726	2.9%
Total Submission		1,339	9,307	14.4%	341	8,383	4.1%	930	7,476	12.4%	209	5,974	3.5%
>=2 weeks & <2 months	In Progress	1	1	100.0%	0	9	0.0%	54	259	20.8%	5	105	4.8%
	Denied	0	0	0.0%	2	4	50.0%	0	0	0.0%	0	4	0.0%
	Approved	0	0	0.0%	0	0	0.0%	0	0	0.0%	1	1	100.0%
	Cancelled by Company	31	199	15.6%	6	106	5.7%	20	183	10.9%	3	63	4.8%
	Revised	0	0	0.0%	0	0	0.0%	2	8	25.0%	0	3	0.0%
	Active	0	0	0.0%	0	0	0.0%	6	22	27.3%	1	34	2.9%
	Completed	136	644	21.1%	33	777	4.2%	78	335	23.3%	22	427	5.2%
Total Submission		168	844	19.9%	41	896	4.6%	160	807	19.8%	32	637	5.0%
>=2 months	In Progress	0	0	0.0%	0	7	0.0%	5	20	25.0%	0	19	0.0%
	Denied	0	0	0.0%	0	0	0.0%	0	0	0.0%	0	0	0.0%
	Approved	0	0	0.0%	0	0	0.0%	1	1	100.0%	0	0	0.0%
	Cancelled by Company	3	42	7.1%	1	31	3.2%	2	30	6.7%	0	14	0.0%
	Revised	0	0	0.0%	0	0	0.0%	0	1	0.0%	0	0	0.0%
	Active	0	1	0.0%	0	2	0.0%	5	24	20.8%	2	49	4.1%
	Completed	35	158	22.2%	8	276	2.9%	20	66	30.3%	5	107	4.7%
Total Submission		38	201	18.9%	9	316	2.8%	33	142	23.2%	7	189	3.7%

If an outage request were submitted after the Annual FTR Auction bidding opening date, the outage would not be considered in the FTR model. If an outage were submitted on time according to the transmission outage rules, it may not be modeled in the FTR model if it is submitted after the Annual FTR Auction bidding opening date. Table 12-39 shows that 88.9 percent of outage requests labelled on time according to rules were submitted or rescheduled after the annual FTR bidding opening date in the 2015 to 2016 planning year.

Table 12-39 Transmission facility outage requests by received status and bidding opening date: Planning periods 2014 to 2015 and 2015 to 2016

	2014/2015						2015/2016					
	On Time			Late			On Time			Late		
Planned Duration	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
<2 weeks	566	8,741	93.9%	13	8,370	99.8%	665	6,811	91.1%	10	5,964	99.8%
>=2 weeks & <2 months	173	671	79.5%	14	882	98.4%	226	581	72.0%	14	623	97.8%
>=2 months	45	156	77.6%	2	314	99.4%	40	102	71.8%	6	183	96.8%
Total	784	9,568	92.4%	29	9,566	99.7%	931	7,494	88.9%	30	6,770	90.0%

Table 12-40 shows that 77.5 percent of late outage requests which were submitted or rescheduled after the Annual FTR Auction bidding opening date were approved and complete in the 2015 to 2016 planning.

Table 12-40 Late transmission facility outage requests that are submitted after annual bidding opening date: Planning periods 2014 to 2015 and 2015 to 2016

	2014/2015			2015/2016		
Planned Duration	Completed Outages	Total	Percent	Completed Outages	Total	Percent
<2 weeks	6,926	8,370	82.7%	4,720	5,964	79.1%
>=2 weeks & <2 months	772	882	87.5%	420	623	67.4%
>=2 months	275	314	87.6%	106	183	57.9%
Total	7,973	9,566	83.3%	5,246	6,770	77.5%

Thus, although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the Annual FTR Auction bidding opening date, the rules have not worked to prevent this since the rule has no direct connection to the annual FTR auction opening date. The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR Auction bidding opening date.

Transmission Facility Outage Analysis in the Day-Ahead Market

Transmission facility outages also affect the energy market. Just as with the FTR Market, it is critical that outages that affect the operating day are known prior to the submission of offers in the Day-Ahead Energy Market both, so that market participants can understand market conditions and so that PJM can accurately model market conditions.

PJM maintains the history of outage requests including all the processed status changes and all the starting or ending date changes. Any such status change is defined as an instance. For example, if an outage request were submitted, received, approved and completed, the four occurrences, termed instances, of the outage request will be stored in the database. If an outage request is revised, that is an instance. There may be more than one instance for each outage request due to the change of the processed status. In the day-ahead market transmission outage analysis, all instances of the outages planned to occur in 2014 and 2015 are included. In the day-ahead market transmission analysis, all submissions or changes of outage requests at or after 12:00 pm on the day before the planned starting date until the hour beginning 23:00 pm on the planned starting date will be defined as late for day-ahead market.

Table 12-41 shows that in 2015 13.0 percent of non-emergency outage request instances were submitted late for the day-ahead market and PJM expected them to cause congestion.

Table 12-41 Transmission facility outage request instance summary by congestion and emergency: 2014 and 2015

		2014				2015			
For Day-ahead Market	Submission Status	Congestion Expected	No Congestion Expected	Total	Percent Congestion	Congestion Expected	No Congestion Expected	Total	Percent Congestion
Late	Emergency	271	4,217	4,488	6.0%	299	3,757	4,056	7.4%
	Non Emergency	2,752	16,266	19,018	14.5%	2,383	15,925	18,308	13.0%
On Time	Emergency	779	15,624	16,403	4.7%	686	11,241	11,927	5.8%
	Non Emergency	14,929	92,753	107,682	13.9%	15,035	91,526	106,561	14.1%
	Total	18,731	128,860	147,591	12.7%	18,403	122,449	140,852	13.1%

Table 12-42 shows that there were 22,364 late outage request instances which were submitted in 2015, of which 3,232 (14.0 percent) had the status submitted, cancelled by company or revised and 192 (0.9 percent) non-emergency instances had the status submitted, cancelled by company or revised and were expected to cause congestion. The top five zones accounted for 57.4 percent of all outages that were late for the day-ahead market in 2015. These zones were: AEP, ATSI, GPU, Dominion and ComEd.

Table 12-42 Late transmission facility outage request instance status summary by congestion and emergency: 2014 and 2015

	2014			2015		
Processed Status	Non Emergency and Congestion Expected	Total	Percent	Non Emergency and Congestion Expected	Total	Percent
Submitted	73	1,859	3.9%	65	1,776	3.7%
Cancelled by Company	84	861	9.8%	80	876	9.1%
Revised	45	524	8.6%	47	480	9.8%
Other	2,550	20,262	12.6%	2,191	19,232	11.4%
Total	2,752	23,506	11.7%	2,383	22,364	10.7%