Generation and Transmission Planning[1]

Overview

Planned Generation and Retirements[2 3]

- **Planned Generation.** As of March 31, 2018, 100,179.4 MW of capacity were in generation request queues for construction through 2022, compared to an installed capacity of 195,493.2 MW. Of the capacity in queues, 10,255.9 MW, or 10.2 percent, are uprates and the rest are new generation. Wind projects account for 18,096.5 MW of nameplate capacity or 18.1 percent of the capacity in the queues. Natural gas fired projects account for 58,962.9 MW of capacity or 58.9 percent of the capacity in the queues.

- **Generation Retirements.** Between 2011 and 2020, 39,125.5 MW have been, or are planned to be, retired. Of that, 13,201.9 MW are planned to retire after March 31, 2018. In the first three months of 2018, 160.2 MW were retired. Of the 13,201.9 MW pending retirement, 6,296.5 MW (47.7 percent) are coal units. The coal unit retirements are a result of low gas prices, low energy prices, low capacity prices and the investments required for compliance with 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 coal fired steam units retire. There are 108.0 MW of coal fired steam capacity and 58,962.9 MW of gas fired capacity in the queue. The replacement of coal fired steam units by units burning natural gas will significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

1 Totals presented in this section include corrections to historical data and may not match totals presented in previous reports.
2 See PJM "Generator Deactivations," at <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
3 See PJM "New Services Queue," at <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.

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.[4] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. 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. The queue process results in a substantial number of projects that drop out. As of March 31, 2018, 3,821 projects, representing 484,439.4 MW, have entered the queue process since its inception. Of those, 769 projects, representing 53,222.7 MW, went into service. Of the projects that entered the queue process, 58.0 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.

- 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."[5] 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.

4 See OATT Parts IV & VI.
5 See OATT § 1 (Transmission Owner).

Regional Transmission Expansion Plan (RTEP)

- The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals are periodically presented to the PJM Board of Managers for authorization. In the first three months of 2018, the PJM Board approved $397.0 million in upgrades.
- There are currently three backbone projects under development, Surry Skiffes Creek 500kV, and the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV.[6]
- Through March 31, 2018, PJM has completed two market efficiency cycles. In the first cycle, PJM received 92 proposals for 11 identified issues. In the second market efficiency cycle, PJM received 96 proposals for four identified issues.
- The first Targeted Market Efficiency Process (TMEP) analysis included the investigation of congestion on 50 market to market flowgates. The study resulted in the evaluation of 13 potential upgrades, resulting in the recommendation of five TMEP projects. The five projects address $59 million in historical congestion, with a TMEP benefit of $99.6 million. The projects have a total cost of $20 million, with a 5.0 average benefit/cost ratio. PJM and MISO presented the five recommended projects to their boards in December, 2017, and both boards approved all five projects.[7]

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 or late and whether or not they will allow the outage.[8]
- There were 19,765 transmission outage requests submitted in the 2017/2018 planning period. Of the requested outages, 76.5 percent were planned for five days or shorter and 7.5 percent were planned for longer than 30 days. Of the requested outages, 44.9 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. First reported 2015. Status: Not adopted.)
- 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.)

6 See "2017 RTEP Process Scope and Input Assumptions White Paper," P 25. <http://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en>.
7 See PJM. "*MISO PJM IPSAC*," (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.
8 PJM. "Manual 03: Transmission Operations," Rev. 52 (Dec. 22, 2017) Section 4.

- 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.[9] (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 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 2015. Status: Not adopted.)
- The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line. (Priority: Medium. First reported 2015. 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. First reported 2015. 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 2014. Status: Partially adopted.)
- The MMU recommends that PJM limit the scope of supplemental projects that can obtain exceptions to the Order No. 1000 process, to ensure maximum competition. (Priority: Medium. First reported 2017. Status: Not adopted.)

9 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.

Managing the generation queues is a highly complex process. The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result. The PJM queue evaluation process should continue to be improved to help 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 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.

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 March 31, 2018, 100,179.4 MW of capacity were in generation request queues for construction through 2022, compared to an installed capacity of 195,493.2 MW. Although it is clear that not all generation in the queues will be built, PJM has added capacity steadily since markets were implemented on April 1, 1999.[10]

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 through T were open for six months. Starting in February 2008, Queues U through 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 AD1 closed on September 30, 2017. Queue AD2 began on October 1, 2017 and closed on March 31, 2018.

Projects that do not meet submission requirements are removed from the queue. All projects that have been entered in a queue and have met the submission requirements 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. 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.[11] 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.[12]

10 See Monitoring Analytics, "New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019," <http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf>.
11 See "PJM Manual 14C Generation and Transmission Interconnection Process," Rev. 12 (June 22, 2017) Section 3.7
12 PJM does not track the duration of suspensions or PJM termination of projects.

Table 12-1 shows MW in queues by expected completion date and MW changes in the queue between December 31, 2017, and March 31, 2018, for ongoing projects, i.e. projects with the status active, under construction or suspended.[13] Projects that are already in service are not included here. The total MW in queues increased by 4,454.1 MW, or 4.7 percent, from 95,725.3 MW at the end of 2017 to 100,179.4 MW on March 31, 2018.

Table 12-1 Queue comparison by expected completion year (MW): December 31, 2017 and March 31, 2018[14]

			Year Change	
Year	As of 12/31/2017	As of 3/31/2018	MW	Percent
2008	12.0	12.0	0.0	0.0%
2009	0.0	0.0	0.0	0.0%
2010	0.0	0.0	0.0	0.0%
2011	110.5	110.5	0.0	0.0%
2012	251.7	251.7	0.0	0.0%
2013	210.5	210.5	0.0	0.0%
2014	327.8	312.8	(15.0)	(4.6%)
2015	985.9	867.6	(118.3)	(12.0%)
2016	2,242.4	1,707.2	(535.2)	(23.9%)
2017	6,257.3	6,039.1	(218.2)	(3.5%)
2018	21,068.4	20,085.5	(982.8)	(4.7%)
2019	25,838.5	26,011.9	173.4	0.7%
2020	24,947.6	28,320.0	3,372.4	13.5%
2021	10,411.9	13,074.7	2,662.9	25.6%
2022	3,060.9	3,175.9	115.0	3.8%
Total	95,725.3	100,179.4	4,454.1	4.7%

Table 12-2 shows the project status changes in more detail and how scheduled queue capacity has changed between December 31, 2017, and March 31, 2018. For example, 9,568.2 MW entered the queue in the first three months of 2018. Of those 9,568.2 MW, 5,114.1 MW have been withdrawn. Of the total 71,633.7 MW marked as active on December 31, 2017, 2,585.2 MW were withdrawn, 2,340.5 MW were suspended, 39.6 MW started construction, and 81.0 MW went into service by March 31, 2018. Analysis of projects that were suspended on December 31, 2017 show that 617.3 MW came out of suspension and are

13 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.
14 Wind and solar capacity in Table 12-1 through Table 12-4 have not been adjusted to reflect derating.

now active and 100.0 MW began construction in the first three months of 2018.

Table 12-2 Change in project status (MW): December 31, 2017 to March 31, 2018

		Status at 3/31/2018				
Status at 12/31/2017	Total at 12/31/2017	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2018)	0.0	4,454.1	0.0	0.0	0.0	5,114.1
Active	71,633.7	66,587.5	81.0	39.6	2,340.5	2,585.2
In Service	52,043.5	0.0	52,043.5	0.0	0.0	0.0
Under Construction	18,990.2	1,050.0	1,098.2	16,383.5	224.0	234.5
Suspended	9,356.1	617.3	0.0	100.0	8,383.0	255.8
Withdrawn	322,847.7	0.0	0.0	0.0	0.0	322,847.7
Total	474,871.1	72,708.9	53,222.7	16,523.1	10,947.5	331,037.2

On March 31, 2018, 100,179.4 MW of capacity were in generation request queues in the status of active, suspended or under construction. Table 12-3 shows each status by fuel type. Of the 72,708.9 MW in the status of Active on March 31, 2018, 34,234.7 MW (47.1 percent) were combined cycle projects. Of the 16,523.1 MW in the status of under construction, 11,774.6 MW (71.3 percent) were combined cycle projects.

Table 12-3 Current project status (MW) by fuel type: March 31, 2018

	Battery	Combined Cycle	CT - Natural Gas	CT - Other	Diesel	Diesel - Landfill Gas	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	Solar	Steam - Biomass	Steam - Coal	Steam - Natural Gas	Steam - Oil	Wind	Total
Active	236.9	34,234.7	4,554.6	34.0	4.0	170.3	4.0	54.0	20.5	139.4	21,329.6	0.0	60.0	94.0	0.0	11,772.9	72,708.9
Suspended	66.3	5,624.1	1,161.6	0.0	0.0	39.8	0.0	0.0	0.0	0.0	378.0	16.0	0.0	0.0	0.0	3,661.7	10,947.5
Under Construction	74.1	11,774.6	929.3	0.0	0.0	21.3	0.0	0.0	23.1	0.0	338.3	62.5	48.0	590.0	0.0	2,661.9	16,523.1
Total	377.2	51,633.4	6,645.5	34.0	4.0	231.4	4.0	54.0	43.6	139.4	22,045.9	78.5	108.0	684.0	0.0	18,096.5	100,179.4

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-M are either in service or have been withdrawn. As of March 31, 2018, there are 100,179.4 MW of capacity in queues that are not yet in service or already withdrawn, of which 10.9 percent are suspended, 16.5 percent are under construction and 72.6 percent have not begun construction.

Table 12-4 Capacity in PJM queues (MW): March 31, 2018[15]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	9,094.0	0.0	0.0	17,252.0	26,346.0
B Expired 31-Jan-99	0.0	4,645.5	0.0	0.0	14,956.7	19,602.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,558.3	4,089.3
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,358.0	8,208.6
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	42.0	0.0	0.0	846.0	888.0
K Expired 31-Jul-03	0.0	99.0	0.0	0.0	485.3	584.3
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	0.0	504.8	0.0	0.0	3,705.6	4,210.4
N Expired 31-Jan-05	0.0	2,398.8	38.0	0.0	8,090.2	10,527.0
O Expired 31-Jul-05	0.0	1,688.2	437.0	0.0	5,466.8	7,592.0
P Expired 31-Jan-06	0.0	3,037.3	253.0	0.0	5,320.5	8,610.8
Q Expired 31-Jul-06	0.0	3,147.9	0.0	0.0	11,385.7	14,533.6
R Expired 31-Jan-07	440.0	2,046.4	0.0	600.0	19,668.9	22,755.3
S Expired 31-Jul-07	70.0	3,669.5	0.0	0.0	12,396.5	16,136.0
T Expired 31-Jan-08	0.0	3,014.0	1,182.5	300.0	23,013.3	27,509.8
U1 Expired 30-Apr-08	0.0	206.9	12.0	0.0	7,937.8	8,156.7
U2 Expired 31-Jul-08	20.0	259.5	568.0	400.0	15,932.2	17,179.7
U3 Expired 31-Oct-08	100.0	334.0	20.0	0.0	2,514.6	2,968.6
U4 Expired 31-Jan-09	100.0	85.2	0.0	400.0	4,445.0	5,030.2
V1 Expired 30-Apr-09	40.0	97.9	100.0	150.0	2,382.8	2,770.7
V2 Expired 31-Jul-09	150.0	989.9	16.1	0.0	3,475.1	4,631.1
V3 Expired 31-Oct-09	200.0	912.0	20.0	300.0	3,522.7	4,954.7
V4 Expired 31-Jan-10	0.0	748.8	0.0	205.0	3,503.0	4,456.8
W1 Expired 30-Apr-10	0.0	345.9	300.0	13.5	5,139.5	5,798.9
W2 Expired 31-Jul-10	72.5	289.2	0.0	23.0	3,018.7	3,403.4
W3 Expired 31-Oct-10	578.5	472.7	83.2	149.9	7,944.8	9,229.1
W4 Expired 31-Jan-11	7.4	1,091.8	409.9	415.0	3,698.2	5,622.3
X1 Expired 30-Apr-11	1,500.0	1,103.8	0.0	500.0	4,200.6	7,304.4
X2 Expired 31-Jul-11	187.5	3,128.4	416.0	585.0	5,578.4	9,895.2
X3 Expired 31-Oct-11	0.0	89.2	23.9	894.0	6,768.0	7,775.1
X4 Expired 31-Jan-12	0.0	954.9	1,994.0	0.0	2,419.4	5,368.3
Y1 Expired 30-Apr-12	106.0	963.4	1,448.1	0.0	5,719.7	8,237.2
Y2 Expired 31-Oct-12	382.8	1,045.8	408.6	229.0	9,227.5	11,293.7
Y3 Expired 30-Apr-13	0.0	459.9	1,170.6	0.0	4,609.2	6,239.6
Z1 Expired 31-Oct-13	713.0	353.0	3,021.8	39.8	3,997.2	8,124.8
Z2 Expired 30-Apr-14	305.6	361.4	2,506.0	52.9	2,949.9	6,175.8
AA1 Expired 31-Oct-14	3,297.3	393.8	727.0	1,915.1	5,665.5	11,998.7
AA2 Expired 30-Apr-15	4,774.2	379.9	603.0	2,435.0	7,874.2	16,066.3
AB1 Expired 31-Oct-15	10,787.1	116.5	704.4	1,195.7	7,648.9	20,452.6
AB2 Expired 31-Mar-16	9,973.1	122.5	55.5	103.6	5,009.2	15,263.9
AC1 Through 30-Sep-16	16,322.6	48.7	4.0	40.5	3,659.7	20,075.6
AC2 Through 30-Apr-17	6,527.5	0.0	0.6	0.5	6,093.1	12,621.6
AD1 Through 30-Sep-17	9,987.0	0.0	0.0	0.0	1,641.9	11,628.9
AD2 Through 31-Mar-18	6,066.8	0.0	0.0	0.0	5,696.5	11,763.3
Total	72,708.9	53,222.7	16,523.1	10,947.5	331,037.2	484,439.4

15 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 with a status of active, suspended or under construction, by unit type, and control zone. As of March 31, 2018, 100,179.4 MW of capacity were in generation request queues for construction through 2022[16] Table 12-5 also shows the planned retirements for each zone.

16 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 nameplate capacity until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent of nameplate capacity until there is operational data to support a different conclusion. PJM derates solar resources to 38 percent of nameplate capacity. Based on the derating of 15,744.0 MW of wind resources and 13,668.5 MW of solar resources, the 100,179.4 MW currently under construction, suspended or active in the queue would be reduced to 70,767.0 MW.

Table 12-5 Queue totals for projects (active, suspended and under construction) by LDA, control zone and fuel (MW): March 31, 2018[17]

LDA	Zone	Battery	Combined Cycle	CT - Natural Gas	CT - Other	Diesel	Diesel - Landfill Gas	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	Solar	Steam - Biomass	Steam - Coal	Steam - Natural Gas	Wind	Total Queue Capacity	Planned Retirments
EMAAC	AECO	20.0	1,439.6	697.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	42.3	0.0	0.0	0.0	25.0	2,224.3	155.0
	DPL	21.0	1,051.0	60.0	0.0	0.0	27.2	0.0	0.0	0.0	0.0	1,447.7	0.0	0.0	0.0	499.6	3,106.5	0.0
	JCPL	65.0	1,587.2	200.0	0.0	0.0	0.0	0.2	20.0	0.0	0.0	174.0	0.0	0.0	0.0	0.0	2,046.4	614.5
	PECO	0.0	1,082.0	132.5	0.0	4.0	0.0	0.0	0.0	0.0	94.0	18.0	0.0	0.0	0.0	0.0	1,330.5	50.8
	PSEG	2.0	2,335.5	906.0	0.0	0.0	0.0	3.4	0.0	0.0	0.0	87.3	0.0	0.0	0.0	0.0	3,334.2	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	0.0	0.0	0.0	0.0
	EMAAC Total	107.9	7,495.3	1,995.5	0.0	4.0	27.2	4.0	20.0	0.0	94.0	1,769.3	0.0	0.0	0.0	524.6	12,041.8	1,431.3
SWMAAC	BGE	0.1	0.0	144.6	14.0	0.0	1.3	0.0	0.0	0.4	17.4	22.0	0.0	0.0	0.0	0.0	199.8	534.0
	Pepco	0.0	1,815.6	117.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	92.8	0.0	0.0	0.0	0.0	2,025.4	0.0
	SWMAAC Total	0.1	1,815.6	261.6	14.0	0.0	1.3	0.0	0.0	0.4	17.4	114.8	0.0	0.0	0.0	0.0	2,225.1	534.0
WMAAC	Met-Ed	0.0	598.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	213.0	0.0	0.0	0.0	0.0	811.9	830.0
	PENELEC	0.0	1,348.0	806.6	0.0	0.0	85.0	0.0	0.0	0.0	0.0	163.8	0.0	0.0	590.0	458.8	3,452.2	110.0
	PPL	30.0	5,165.0	246.9	0.0	0.0	19.9	0.0	0.0	0.0	0.0	30.0	16.0	0.0	0.0	531.1	6,038.9	0.0
	WMAAC Total	30.0	7,111.9	1,053.5	0.0	0.0	104.9	0.0	0.0	0.0	0.0	406.8	16.0	0.0	590.0	989.8	10,302.9	940.0
Non-MAAC	AEP	20.0	6,941.0	1,007.2	0.0	0.0	12.0	0.0	34.0	0.0	28.0	5,442.5	0.0	72.0	30.0	8,009.5	21,596.2	0.0
	APS	21.5	5,820.7	139.9	0.0	0.0	79.8	0.0	0.0	15.0	0.0	995.3	0.0	10.0	0.0	1,186.4	8,268.6	1,307.0
	ATSI	0.0	6,131.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	846.0	0.0	0.0	0.0	1,316.1	8,363.0	2,910.0
	ComEd	84.0	7,774.2	1,635.6	0.0	0.0	6.2	0.0	0.0	22.7	0.0	1,071.5	0.0	0.0	64.0	4,952.2	15,610.4	2.1
	DAY	19.9	1,150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	762.9	0.0	12.0	0.0	100.0	2,044.8	2,364.0
	DEOK	19.8	513.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	300.0	0.0	0.0	0.0	0.0	852.8	0.0
	DLCO	20.0	0.0	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	245.0	1,777.0
	Dominion	54.0	6,880.7	202.2	0.0	0.0	0.0	0.0	0.0	5.5	0.0	9,946.9	62.5	14.0	0.0	1,018.0	18,183.8	1,936.5
	EKPC	0.0	0.0	75.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	330.0	0.0	0.0	0.0	0.0	405.0	0.0
	RMU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	0.0	0.0	40.0	0.0
	Non-MAAC Total	239.2	35,210.6	3,334.9	20.0	0.0	98.0	0.0	34.0	43.2	28.0	19,755.1	62.5	108.0	94.0	16,582.1	75,609.6	10,296.6
	Total	377.2	51,633.4	6,645.5	34.0	4.0	231.4	4.0	54.0	43.6	139.4	22,045.9	78.5	108.0	684.0	18,096.5	100,179.4	13,201.9

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 coal fired steam units retire. As of March 31, 2018, there were 58,962.9 MW of natural gas fired capacity active, suspended or under construction in PJM. As of March 31, 2018, there were only 108.0 MW of coal fired steam capacity active, suspended or under construction in PJM. With respect to retirements, 6,296.5 MW of coal fired steam capacity and 1,471.8 MW of natural gas capacity are slated for deactivation between March 31, 2018, and December 31, 2021. The replacement of coal fired steam units by natural gas units will significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

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

Planned Retirements

As shown in Table 12-6, 39,125.5 MW have been, or are planned to be, retired between 2011 and 2021.[18] Of that, 13,201.9 MW are planned to retire after March 31, 2018. In the first three months of 2018, 160.2 MW were retired. Of the 13,201.9 MW pending retirement, 6,296.5 MW (47.7 percent) are steam fired coal units. The coal unit retirements were a result of low gas prices, low capacity prices and the investments required for compliance with the EPA's Mercury and Air Toxics Standards (MATS) for some units.

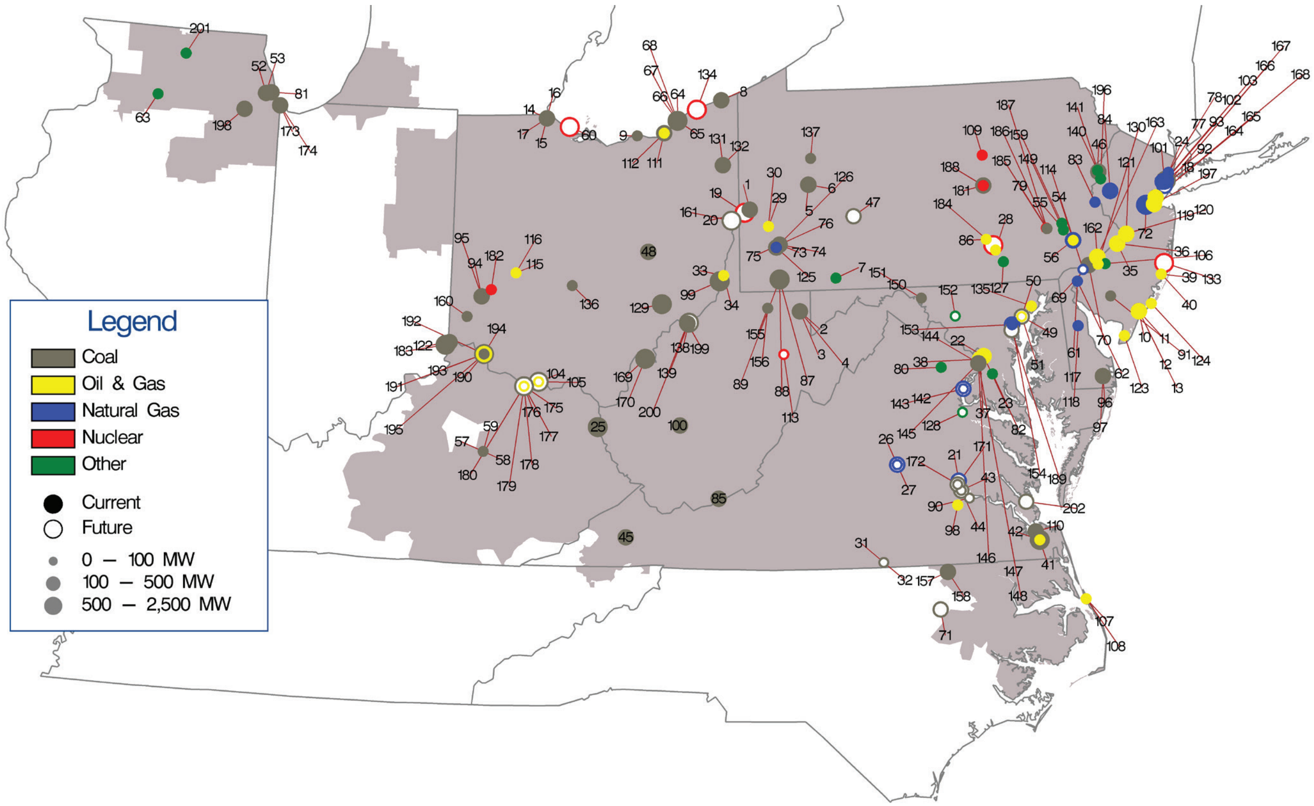
Table 12-6 Summary of PJM unit retirements by fuel (MW): 2011 through 2021

	Battery	Combined Cycle	CT-Natural Gas	CT-Other	Diesel	Diesel-Landfill Gas	Hydro-Pumped Storage	Nuclear	Steam-Biomass	Steam-Coal	Steam-Natural Gas	Steam-Oil	Wind	Total
Retirements 2011	0.0	0.0	0.0	128.3	2.7	0.0	0.0	0.0	0.0	543.0	522.5	0.0	0.0	1,196.5
Retirements 2012	0.0	0.0	250.0	240.0	0.0	0.0	0.0	0.0	16.0	5,907.9	0.0	548.0	0.0	6,961.9
Retirements 2013	0.0	0.0	0.0	0.0	5.9	7.0	0.0	0.0	8.0	2,589.9	82.0	166.0	0.0	2,858.8
Retirements 2014	0.0	0.0	136.0	422.0	0.0	15.3	0.0	0.0	0.0	2,239.0	158.0	0.0	0.0	2,970.3
Retirements 2015	0.0	0.0	1,319.0	858.2	10.3	0.0	0.0	0.0	0.0	7,064.8	0.0	0.0	10.4	9,262.7
Retirements 2016	0.0	0.0	0.0	71.0	8.0	3.9	0.5	0.0	0.0	243.0	74.0	0.0	0.0	400.4
Retirements 2017	40.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	2,038.0	34.0	0.0	0.0	2,112.8
Retirements 2018	0.0	0.0	0.0	0.0	8.2	4.0	0.0	0.0	0.0	0.0	0.0	148.0	0.0	160.2
Planned Retirements (April 2018 and later)	27.4	425.0	0.0	39.6	9.0	2.1	0.0	5,330.5	25.0	6,296.5	1,046.8	0.0	0.0	13,201.9
Total	67.4	425.0	1,705.0	1,759.1	44.1	33.1	0.5	5,330.5	49.0	26,922.1	1,917.3	862.0	10.4	39,125.5

18 See PJM "Generator Deactivations," at <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.

A map of unit retirements between 2011 and 2021 is shown in Figure 12-1 with a mapping to unit names identified in Table 12-7.

Figure 12-1 Map of PJM unit retirements: 2011 through 2021[19]



19 Units included in the "Oil and Gas" category include those using heavy oil, light oil, kerosene and diesel.

Table 12-7 Unit identification for map of PJM unit retirements: 2011 through 2021

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AES Beaver Valley	36	Burlington 9	71	Edgecomb NUG (Rocky 1-2)	106	Kinsley Landfill	141	Portland 2	176	Stuart 2
2	Albright 1	37	Buzzard Point East Banks 1,2,4-8	72	Edison 1-3	107	Kitty Hawk GT 1	142	Possum Point 3	177	Stuart 3
3	Albright 2	38	Buzzard Point West Banks 1-9	73	Elrama 1	108	Kitty Hawk GT 2	143	Possum Point 4	178	Stuart 4
4	Albright 3	39	Cedar 1	74	Elrama 2	109	Koppers Co. IPP	144	Potomac River 1	178	Stuart Diesels 1-4
5	Armstrong 1	40	Cedar 2	75	Elrama 3	110	Lake Kingman	145	Potomac River 2	180	Stuart Diesels 1-4
6	Armstrong 2	41	Chesapeake 1-4	76	Elrama 4	111	Lake Shore 18	146	Potomac River 3	151	Sunbury 1-4
7	Arnold (Green Mtn. Wind Farm	42	Chesapeake 7-10	77	Essex 10-11	112	Lake Shore EMD	147	Potomac River 4	152	Tait Battery
8	Ashtabula 5	43	Chesterfield 3	78	Essex 12	113	Laurel Mountain Battery	148	Potomac River 5	153	Tanners Creek 1-4
9	Avon Lake 7	44	Chesterfield 4	79	Evergreen Power United Corstack	114	MH50 Markus Hook Co-gen	149	Pottstown LF (Moser)	154	Three Mile Island Unit 1
10	BL England 1	45	Clinch River 3	80	Fauquier County Landfill	115	Mad River CTs A	150	R Paul Smith 3	155	Titus 1
11	BL England 2	46	Columbia Dam Hydro	81	Fisk Street 19	116	Mad River CTs B	151	R Paul Smith 4	156	Titus 2
12	BL England 3	47	Colver Power Project	82	GUDE Landfill	117	McKee 1	152	Reichs Ford Road Landfill Generator	157	Titus 3
13	BL England Diesel Units 1-4	48	Conesville 3	83	Gilbert 1-4	118	McKee 2	153	Riverside 4	158	Viking Energy NUG
14	Bay Shore 1	49	Crane 1	84	Glen Gardner 1-8	119	Mercer 1	154	Riverside 6	159	Wagner 2
15	Bay Shore 2	50	Crane 2	85	Glen Lyn 5-6	120	Mercer 2	155	Riversville 5	160	Walter C Beckjord 1
16	Bay Shore 3	51	Crane GT1	86	Harrisburg 4 CT	121	Mercer 3	156	Riversville 6	161	Walter C Beckjord 2
17	Bay Shore 4	52	Crawford 7	87	Hatfield's Ferry 1	122	Miami Fort 6	157	Roanoke Valley 1	162	Walter C Beckjord 3
18	Bayonne Cogen Plant (CC)	53	Crawford 8	88	Hatfield's Ferry 2	123	Middle 1-3	158	Roanoke Valley 2	163	Walter C Beckjord 4
19	Beaver Valley U1 Nuclear Generating Unit	54	Cromby 1	89	Hatfield's Ferry 3	124	Missouri Ave B,C,D	159	Rolling Hills Landfill Generator	164	Walter C Beckjord 5-6
20	Beaver Valley U2 Nuclear Generating Unit	55	Cromby 2	90	Hopewell James River Cogeneration	125	Mitchell 2	160	SMART Paper	165	Walter C Beckjord GT 1-4
21	Bellemeade	56	Cromby D	91	Howard Down 10	126	Mitchell 3	161	Sammis 1-4	166	Warren County Landfill
22	Benning 15	57	Dale 1-2	92	Hudson 1	127	Modern Power Landfill NUG	162	Schuylkill 1	167	Werner 1-4
23	Benning 16	58	Dale 3	93	Hudson 2	128	Morris Landfill Generator	163	Schuylkill Diesel	168	Will County 3
24	Bergen 3	59	Dale 4	94	Hutchings 1-3, 5-6	129	Muskingum River 1-5	164	Sewaren 1	169	Willow Island 1
25	Big Sandy 2	60	Davis Besse U1 Nuclear Generating Unit	95	Hutchings 4	130	National Park 1	165	Sewaren 2	170	Willow Island 2
26	Bremo 3	61	Deepwater 1	96	Indian River 1	131	Niles 1	166	Sewaren 3	171	Winnebago Landfill
27	Bremo 4	62	Deepwater 6	97	Indian River 3	132	Niles 2	167	Sewaren 4	172	Yorktown 1-2
28	Brunner Island Diesels	63	Dixon Lee Landfill Generator	98	Ingenco Petersburg	133	Oyster Creek	168	Sewaren 6		
29	Brunot Island 1B	64	Eastlake 1	99	Kammer 1-3	134	Perry U1 Nuclear Generating Unit	169	Sporn 1-4		
30	Brunot Island 1C	65	Eastlake 2	100	Kanawha River 1-2	135	Perryman 2	170	Sporn 5		
31	Buggs Island 1 (Mecklenberg)	66	Eastlake 3	101	Kearny 10	136	Picway 5	171	Spruance NUG1 (Rich 1-2)		
32	Buggs Island 2 (Mecklenberg)	67	Eastlake 4	102	Kearny 11	137	Piney Creek NUG	172	Spruance NUG2 (Rich 3-4)		
33	Burger 3	68	Eastlake 5	103	Kearny 9	138	Pleasants Power Station U1	173	State Line 3		
34	Burger EMD	69	Eddystone 1	104	Killen 2	139	Pleasants Power Station U2	174	State Line 4		
35	Burlington 8,11	70	Eddystone 2	105	Killen CT	140	Portland 1	175	Stuart 1		

The list of pending retirements is shown in Table 12-8.

Table 12-8 Planned retirement of PJM units: March 31, 2018

Unit	Zone	ICAP (MW)	Unit Type	Projected Deactivation Date
Yorktown 1-2	Dominion	323.0	Steam-Coal	13-Mar-18
Laurel Mountain Battery	APS	27.4	Battery	16-Mar-18
Bellemeade	Dominion	267.0	Combined Cycle	09-Apr-18
Buggs Island 1 (Mecklenberg)	Dominion	69.0	Steam-Coal	09-Apr-18
Buggs Island 2 (Mecklenberg)	Dominion	69.0	Steam-Coal	09-Apr-18
Bremo 3	Dominion	71.0	Steam-Natural Gas	09-Apr-18
Bremo 4	Dominion	156.0	Steam-Natural Gas	09-Apr-18
Evergreen Power United Corstack	Met-Ed	25.0	Steam-Biomass	03-May-18
Reichs Ford Road Landfill Generator	APS	1.6	CT-Other	31-May-18
Morris Landfill Generator	ComEd	2.1	Diesel-Landfill Gas	31-May-18
Hopewell James River Cogeneration	Dominion	89.0	Steam-Coal	31-May-18
Crane 1	BGE	190.0	Steam-Coal	01-Jun-18
Crane 2	BGE	195.0	Steam-Coal	01-Jun-18
Killen CT	DAY	24.0	CT-Other	01-Jun-18
Stuart Diesels 1-4	DAY	9.0	Diesel	01-Jun-18
Killen 2	DAY	600.0	Steam-Coal	01-Jun-18
Stuart 2	DAY	577.0	Steam-Coal	01-Jun-18
Stuart 3	DAY	577.0	Steam-Coal	01-Jun-18
Stuart 4	DAY	577.0	Steam-Coal	01-Jun-18
Bayonne Cogen Plant (CC)	PSEG	158.0	Combined Cycle	01-Jun-18
Sewaren 1	PSEG	104.0	Steam-Natural Gas	01-Jun-18
Sewaren 2	PSEG	118.0	Steam-Natural Gas	01-Jun-18
Sewaren 3	PSEG	107.0	Steam-Natural Gas	01-Jun-18
Sewaren 4	PSEG	124.0	Steam-Natural Gas	01-Jun-18
Oyster Creek Nuclear Generating Station	JCPL	614.5	Nuclear	01-Oct-18
Chesterfield 3	Dominion	97.5	Steam-Coal	01-Dec-18
Chesterfield 4	Dominion	163.0	Steam-Coal	01-Dec-18
Possum Point 3	Dominion	96.0	Steam-Natural Gas	01-Dec-18
Possum Point 4	Dominion	220.0	Steam-Natural Gas	01-Dec-18
Pleasants Power Station U1	APS	639.0	Steam-Coal	01-Jan-19
Pleasants Power Station U2	APS	639.0	Steam-Coal	01-Jan-19
Spruance NUG1 (aka Spruance 1 Rich 1-2)	Dominion	115.5	Steam-Coal	12-Jan-19
Spruance NUG2 (aka Spruance 2 Rich 3-4)	Dominion	85.0	Steam-Coal	12-Jan-19
BL England 2	AECO	155.0	Steam-Coal	30-Apr-19
MH50 Markus Hook Co-gen	PECO	50.8	Steam-Natural Gas	01-Jun-19
Three Mile Island Unit 1 Nuclear Generating Station	Met-Ed	805.0	Nuclear	30-Sep-19
Crane GT1	BGE	14.0	CT-Other	31-Oct-19
Davis Besse U1 Nuclear Generating Unit	ATSI	894.0	Nuclear	31-May-20
Sammis 1-4	ATSI	640.0	Steam-Coal	31-May-20
Wagner 2	BGE	135.0	Steam-Coal	01-Jun-20
Colver Power Project	PENELEC	110.0	Steam-Coal	01-Sep-20
Bay Shore 1	ATSI	136.0	Steam-Coal	01-Oct-20
Edgecomb NUG (aka Edgecomb Rocky 1-2)	Dominion	115.5	Steam-Coal	31-Oct-20
Perry U1 Nuclear Generating Unit	ATSI	1,240.0	Nuclear	31-May-21
Beaver Valley U1 Nuclear Generating Unit	DLCO	892.0	Nuclear	31-May-21
Beaver Valley U2 Nuclear Generating Unit	DLCO	885.0	Nuclear	31-Oct-21
Total		13,201.9		

Table 12-9 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2021, while Table 12-10 shows these retirements by state. The majority, 68.8 percent, of all MW retiring during this period are coal fired steam units. These coal fired steam units have an average age of 53.5 years and an average size of 176.0 MW. Over half of the retiring coal fired steam units, 51.7 percent, are located in either Ohio or Pennsylvania. Retirements have generally consisted of smaller subcritical coal fired steam units and those without adequate environmental controls to remain viable in the future.

Table 12-9 Retirements by fuel type: 2011 through 2021

Fuel Type	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Battery	2	33.7	5.4	67.4	0.2%
Combined Cycle	2	212.5	25.5	425.0	1.1%
Combustion Turbine	89	39.1	43.0	3,464.1	8.9%
Natural Gas	41	41.6	44.0	1,705.0	4.4%
Other	48	36.6	41.9	1,759.1	4.5%
Diesel	10	4.4	45.7	44.1	0.1%
Diesel (Landfill Gas)	9	3.7	11.1	33.1	0.1%
Fuel Cell	0	0.0	0.0	0.0	0.0%
Nuclear	6	888.4	41.6	5,330.5	13.6%
Hydro	1	0.5	113.8	0.5	0.0%
Pumped Storage	1	0.5	113.8	0.5	0.0%
Run of River	0	0.0	0.0	0.0	0.0%
Solar	0	0.0	0.0	0.0	0.0%
Steam	177	130.2	44.2	29,750.4	76.0%
Biomass	3	16.3	18.3	49.0	0.1%
Coal	153	176.0	53.5	26,922.1	68.8%
Natural Gas	17	112.8	59.6	1,917.3	4.9%
Oil	4	215.5	45.5	862.0	2.2%
Wind	1	10.4	15.6	10.4	0.0%
Total	297	131.7	48.0	39,125.5	100.0%

Table 12-10 Retirements (MW) by fuel type and state: 2011 through 2021

State	Battery	Combined Cycle	CT-Natural Gas	CT-Other	Diesel	Diesel-Landfill Gas	Hydro-Pumped Storage	Nuclear	Steam-Biomass	Steam-Coal	Steam-Natural Gas	Steam-Oil	Wind	Total
DC	0.0	0.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	548.0	0.0	788.0
DE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	254.0	34.0	0.0	0.0	288.0
IL	0.0	0.0	0.0	0.0	0.0	12.5	0.0	0.0	0.0	1,624.0	0.0	0.0	0.0	1,636.5
IN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0	0.0	0.0	0.0	982.0
KY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	995.0	0.0	0.0	0.0	995.0
MD	0.0	0.0	115.0	66.6	0.0	0.8	0.0	0.0	0.0	635.0	74.0	0.0	0.0	891.4
NC	0.0	0.0	0.0	31.0	0.0	0.0	0.0	0.0	0.0	324.5	0.0	0.0	0.0	355.5
NJ	0.0	158.0	1,590.0	1,040.2	8.0	9.8	0.5	614.5	0.0	1,543.0	932.5	148.0	0.0	6,044.5
OH	40.0	0.0	0.0	262.0	19.3	0.0	0.0	2,134.0	0.0	9,248.6	0.0	0.0	0.0	11,703.9
PA	0.0	0.0	0.0	52.0	13.9	8.0	0.0	2,582.0	49.0	4,658.0	333.8	166.0	10.4	7,873.1
VA	0.0	267.0	0.0	67.3	2.9	2.0	0.0	0.0	0.0	2,739.0	543.0	0.0	0.0	3,621.2
WV	27.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,919.0	0.0	0.0	0.0	3,946.4
Total	67.4	425.0	1,705.0	1,759.1	44.1	33.1	0.5	5,330.5	49.0	26,922.1	1,917.3	862.0	10.4	39,125.5

Generation Deactivations in 2018

Table 12-11 shows the units that were deactivated in the first three months of 2018.

Table 12-11 Unit deactivations: January through March, 2018

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Age (Years)	Retirement Date
Biogas Energy Solutions, LLC	Dixon Lee Landfill Generator	4.0	Diesel-Landfill Gas	ComEd	4.8	10-Jan-18
Rockland Capital Energy Investments, LLC	BL England 3	148.0	Steam-Oil	AECO	43.2	24-Jan-18
Riverstone Holdings LLC	Brunner Island Diesels	8.2	Diesel	PPL	50.8	25-Feb-18
Total		160.2				

Existing Generation Mix

As of March 31, 2018, PJM had an installed capacity of 195,493.2 MW (Table 12-12). 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 12-12 Existing PJM capacity: March 31, 2018 (By zone and unit type (MW))[20]

Zone	Battery	Combined Cycle	CT - Natural Gas	CT - Other	Diesel	Diesel - LFG	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	Solar	Steam - Biomass	Steam - Coal	Steam - Natural Gas	Steam - Oil	Wind	Total
AECO	0.0	901.9	544.7	26.0	4.0	10.6	1.6	0.0	0.0	0.0	59.4	0.0	613.9	0.0	0.0	7.5	2,169.5
AEP	6.0	6,990.0	3,661.2	21.0	0.0	21.3	0.0	66.0	486.9	2,071.0	14.7	50.0	14,727.8	738.0	0.0	2,490.0	31,343.9
APS	78.9	1,129.0	1,223.3	3.6	29.6	18.3	0.0	0.0	129.2	0.0	55.1	0.0	5,409.0	0.0	0.0	1,191.5	9,267.5
ATSI	0.0	1,570.5	958.0	660.3	18.5	45.2	0.0	0.0	0.0	2,134.0	0.0	0.0	5,394.0	325.0	0.0	0.0	11,105.5
BGE	0.0	0.0	500.1	281.8	0.0	7.2	0.0	0.0	0.4	1,716.0	1.1	57.0	2,098.0	240.5	397.0	0.0	5,299.1
ComEd	127.5	2,646.1	6,940.3	226.2	0.0	40.4	0.0	0.0	0.0	10,473.5	9.0	0.0	3,840.1	1,326.0	0.0	3,187.9	28,817.0
DAY	0.0	0.0	1,344.5	24.0	43.0	4.5	0.0	0.0	0.0	0.0	1.1	0.0	2,331.0	0.0	0.0	0.0	3,748.1
DEOK	20.0	522.2	598.0	56.0	0.0	4.8	0.0	0.0	112.0	0.0	0.0	0.0	1,857.0	47.0	0.0	0.0	3,217.0
DLCO	0.0	244.0	0.0	15.0	0.0	0.0	0.0	0.0	6.3	1,777.0	0.0	0.0	565.0	0.0	0.0	0.0	2,607.3
Dominion	0.0	7,766.6	3,495.3	266.4	39.0	112.8	0.0	3,003.0	586.3	3,581.3	495.4	451.4	4,843.6	578.0	1,586.0	208.0	27,013.1
DPL	0.0	1,742.5	1,298.2	478.2	88.0	14.1	30.0	0.0	0.0	0.0	213.4	0.0	410.0	882.0	153.0	0.0	5,309.4
EKPC	0.0	0.0	774.0	0.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	1,687.0	0.0	0.0	0.0	2,531.0
JCPL	0.0	2,402.5	531.1	232.0	0.0	16.1	0.4	400.0	0.0	614.5	260.6	10.0	0.0	0.0	0.0	0.0	4,467.2
Met-Ed	0.0	1,616.0	2.0	398.5	0.0	33.4	0.0	0.0	19.0	805.0	0.0	85.0	115.0	0.0	0.0	0.0	3,073.9
PECO	1.0	3,209.0	0.0	834.0	2.0	0.9	0.0	1,070.0	572.0	4,546.8	3.0	163.0	3.3	812.8	0.0	0.0	11,217.8
PENELEC	28.4	850.0	350.5	57.0	106.8	17.8	0.0	513.0	77.8	0.0	0.0	42.0	6,141.5	610.0	0.0	958.8	9,753.6
Pepco	0.0	1,710.0	764.2	308.0	0.0	11.1	0.0	0.0	0.0	0.0	0.0	52.0	2,433.0	1,164.1	0.0	0.0	6,442.4
PPL	20.0	1,902.5	252.0	150.1	17.0	19.7	0.0	0.0	706.6	2,520.0	15.0	34.0	2,642.9	2,449.0	10.0	216.5	10,955.3
PSEG	4.0	4,000.3	1,039.2	0.0	0.0	6.0	0.0	0.0	5.0	3,493.0	185.6	188.1	0.0	456.0	0.0	0.0	9,377.2
XIC	0.0	0.0	691.6	0.0	0.0	0.0	0.0	0.0	269.1	1,140.0	0.0	0.0	5,676.8	0.0	0.0	0.0	7,777.5
Total	285.8	39,203.1	24,968.2	4,038.1	347.9	384.1	32.0	5,052.0	3,040.6	34,872.1	1,313.4	1,132.5	60,788.9	9,628.4	2,146.0	8,260.2	195,493.2

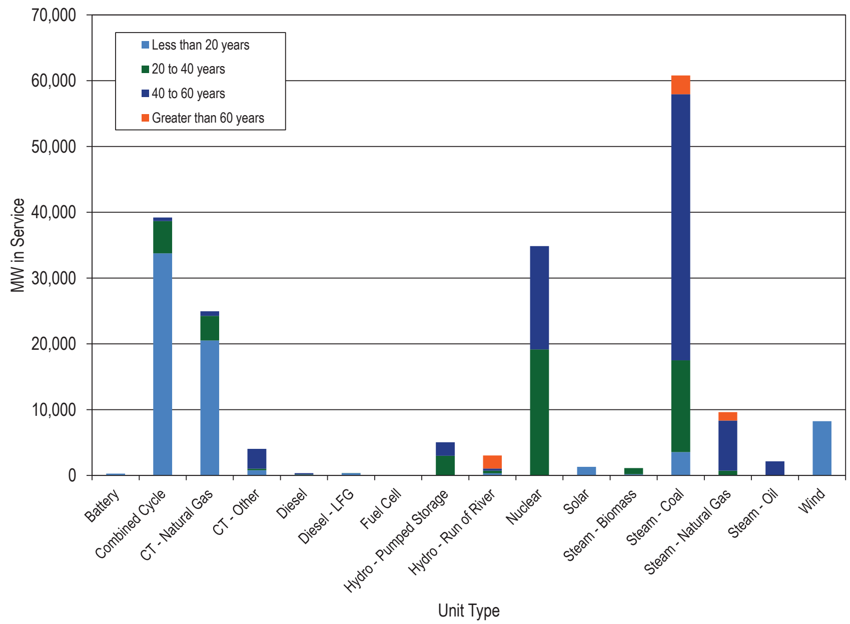
20 The capacity described in this section refers to all capacity in PJM at the summer installed capacity rating, regardless of whether the capacity entered the RPM Auction. This table previously included external units.

Table 12-13 and Figure 12-2 show the age of PJM generators by unit type as of March 31, 2018. Units older than 40 years comprise 78,808.8 MW (40.3 percent) of the total capacity of 195,493.2 MW.

Table 12-13 PJM capacity (MW) by age (years): March 31, 2018

Age (years)	Battery	Combined Cycle	CT - Natural Gas	CT - Other	Diesel	Diesel - LFG	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	Solar	Steam - Biomass	Steam - Coal	Steam - Natural Gas	Steam - Oil	Wind	Total
Less than 20	285.8	33,777.6	20,519.9	801.5	128.4	343.7	32.0	0.0	339.2	0.0	1,313.4	194.4	3,564.0	82.0	0.0	8,260.2	69,642.0
20 to 40	0.0	4,893.5	3,746.1	241.2	37.0	40.4	0.0	3,003.0	385.2	19,158.9	0.0	938.1	13,948.2	650.8	0.0	0.0	47,042.4
40 to 60	0.0	532.0	702.2	2,995.4	182.5	0.0	0.0	2,049.0	340.0	15,713.2	0.0	0.0	40,435.4	7,609.1	2,146.0	0.0	72,704.8
Greater than 60	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,976.2	0.0	0.0	0.0	2,841.3	1,286.5	0.0	0.0	6,104.0
Total	285.8	39,203.1	24,968.2	4,038.1	347.9	384.1	32.0	5,052.0	3,040.6	34,872.1	1,313.4	1,132.5	60,788.9	9,628.4	2,146.0	8,260.2	195,493.2

Figure 12-2 PJM capacity (MW) by age (years): March 31, 2018



Generation and Transmission Interconnection Planning Process

PJM made changes to the queue process in May 2012.[21] 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.

Interconnection Queue Analysis

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.

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

21 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).

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.[22] 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.

Withdrawn Projects

Table 12-15 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the 2,142 projects withdrawn, 1,033 (48.2 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.[23] [24] Of the 2,142 projects withdrawn, 406 (19.0 percent) were withdrawn after the completion of a Construction Service Agreement.

Table 12-15 Last milestone at time of withdrawal: January 1997 through March 2018

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	350	16.3%	92	868
Feasibility Study	683	31.9%	291	1,633
System Impact Study	440	20.5%	771	3,248
Facilities Study	263	12.3%	1,088	3,454
Construction Service Agreement (CSA) or beyond	406	19.0%	1,253	4,249
Total	2,142	100.0%		

Table 12-16 and Table 12-17 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 1,010 days, or 2.8 years, between entering

22 See PJM. "Manual 14B: PJM Region Transmission Planning Process," Rev. 40 (Oct. 26, 2017), p.82.
23 "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," Rev. 12 (June 22, 2017).
24 See PJM. "Manual 14C: Generation and Transmission Interconnection Facility Construction," Rev. 12 (June 22, 2017).

a queue and going into service. For withdrawn projects, there is an average time of 616 days, or 1.7 years, between entering a queue and withdrawing.

Table 12-16 Average project queue times (days): March 31, 2018[25]

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	566	564	5	4,211
In-Service	1,010	726	0	4,024
Suspended	1,674	1,002	369	4,177
Under Construction	1,846	1,048	486	4,933
Withdrawn	616	689	0	4,249

Average Time in Queue

Table 12-17 presents information on the time in the stages of the queue for those projects not yet in service or already withdrawn. Of the 835 projects in the queue as of March 31, 2018, 207 had a completed feasibility study and 311 were under construction.

Table 12-17 PJM generation planning summary: March 31, 2018

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	130	15.6%	131	884
Feasibility Study	207	24.8%	424	1,195
System Impact Study	157	18.8%	783	3,471
Facilities Study	30	3.6%	1,261	3,279
Construction Service Agreement (CSA) or beyond	311	37.2%	1,452	4,933
Total	835	100.0%		

Queue Analysis by Fuel Group

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 12-18 shows the number of projects that entered the queue by year. The number of queue entries has increased during the past several years, primarily by renewable projects (solar, hydro, storage, biomass, wind). Of the 1,169 projects entered in 2015, 2016, 2017 and the first three months of 2018, 906 projects, 77.5 percent, were renewable. Of the 106 projects entered in the first three months of 2018, 91 projects, 85.5 percent, were renewable.

Table 12-18 Number of projects entered in the queue: March 31, 2018

	Fuel Group			
Year Entered	Nuclear	Renewable	Traditional	Grand Total
1997	2	0	11	13
1998	0	0	18	18
1999	1	5	84	90
2000	2	3	78	83
2001	4	6	81	91
2002	3	15	33	51
2003	1	34	18	53
2004	4	17	33	54
2005	3	75	55	133
2006	9	67	81	157
2007	9	65	145	219
2008	3	109	104	216
2009	10	109	54	173
2010	5	375	61	441
2011	6	268	81	355
2012	2	70	87	159
2013	1	75	78	154
2014	0	121	71	192
2015	0	196	113	309
2016	2	320	77	399
2017	2	299	54	355
2018	0	91	15	106
Total	69	2,320	1,432	3,821

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 40.5 percent of the nameplate MW currently active, suspended or under construction in the queue (Table 12-19).

Table 12-19 Queue details by fuel group: March 31, 2018

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	8	1.0%	139.4	0.1%
Renewable	609	72.9%	40,621.2	40.5%
Traditional	218	26.1%	59,418.8	59.3%
Total	835	100.0%	100,179.4	100.0%

25 The queue data shows that some projects were withdrawn and a withdrawal date was not identified. These projects were removed for the purposes of this analysis.

Queue Analysis by Fuel Type and Project Classification

Table 12-20 shows the current status of all generation queue projects by fuel type and project classification from January 1, 1997, through March 31, 2018. For example, between January 1, 1997 and March 31, 2018, 159 nameplate capacity upgrades at natural gas fired CT facilities have completed the queue process and are in service.

Since 1997, there have been a total of 3,821 projects in PJM generation queues. A total of 3,094 projects have been classified as new generation and 727 projects have been classified as upgrades. Wind, solar and natural gas projects have accounted for 3,142 projects, or 82.2 percent, of all 3,821 generation queue projects.

Table 12-20 Status of all generation queue projects: January 1997 through March 2018

		Number of Projects																
Project Status	Project Classification	Battery	Combined Cycle	CT - Natural Gas	CT - Other	Diesel	Diesel - Landfill Gas	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	Solar	Steam - Biomass	Steam - Coal	Steam - Natural Gas	Steam - Oil	Wind	Total
In Service	New Generation	18	6	162	3	5	2	3	0	10	1	123	6	9	1	4	65	418
	Upgrade	3	14	159	5	3	4	0	0	18	42	16	6	49	3	14	15	351
Under Construction	New Generation	23	15	6	0	0	2	0	0	3	0	26	0	0	1	0	16	92
	Upgrade	2	10	9	0	0	1	0	0	0	0	1	1	2	0	0	1	27
Suspended	New Generation	7	7	7	0	0	2	0	0	0	0	32	1	0	0	0	19	75
	Upgrade	2	3	2	0	0	0	0	0	0	0	0	0	0	0	0	1	8
Withdrawn	New Generation	89	28	451	11	12	30	8	0	39	9	860	32	55	2	9	383	2,018
	Upgrade	14	18	77	2	2	2	2	0	4	9	22	2	13	0	13	19	199
Active	New Generation	15	37	14	1	0	11	19	1	1	1	338	0	0	0	0	53	491
	Upgrade	2	41	31	1	1	6	0	1	1	7	33	0	3	3	0	12	142
Total Projects	New Generation	152	93	640	15	17	47	30	1	53	11	1,379	39	64	4	13	536	3,094
	Upgrade	23	86	278	8	6	13	2	1	23	58	72	9	67	6	27	48	727

Table 12-21 shows the MW in Table 12-20 by share of classification as new generation or upgrade. Within a fuel type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 78.3 percent of all hydro – run of river projects classified as upgrades are currently in service in PJM, 17.4 percent of hydro – run of river upgrades were withdrawn and 4.3 percent of hydro – run of river upgrades are active in the queue.

Table 12-21 Status of all generation queue projects as a percent of total projects by classification: January 1997 through March 2018

		Percent of Total Projects by Classification															
Project Status	Project Classification	Battery	Combined Cycle	CT - Natural Gas	CT - Other	Diesel	Diesel - Landfill Gas	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	Solar	Steam - Biomass	Steam - Coal	Steam - Natural Gas	Steam - Oil	Wind
In Service	New Generation	11.8%	6.5%	25.3%	20.0%	29.4%	4.3%	10.0%	0.0%	18.9%	9.1%	8.9%	15.4%	14.1%	25.0%	30.8%	12.1%
	Upgrade	13.0%	16.3%	57.2%	62.5%	50.0%	30.8%	0.0%	0.0%	78.3%	72.4%	22.2%	66.7%	73.1%	50.0%	51.9%	31.3%
Under Construction	New Generation	15.1%	16.1%	0.9%	0.0%	0.0%	4.3%	0.0%	0.0%	5.7%	0.0%	1.9%	0.0%	0.0%	25.0%	0.0%	3.0%
	Upgrade	8.7%	11.6%	3.2%	0.0%	0.0%	7.7%	0.0%	0.0%	0.0%	0.0%	1.4%	11.1%	3.0%	0.0%	0.0%	2.1%
Suspended	New Generation	4.6%	7.5%	1.1%	0.0%	0.0%	4.3%	0.0%	0.0%	0.0%	0.0%	2.3%	2.6%	0.0%	0.0%	0.0%	3.5%
	Upgrade	8.7%	3.5%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.1%
Withdrawn	New Generation	58.6%	30.1%	70.5%	73.3%	70.6%	63.8%	26.7%	0.0%	73.6%	81.8%	62.4%	82.1%	85.9%	50.0%	69.2%	71.5%
	Upgrade	60.9%	20.9%	27.7%	25.0%	33.3%	15.4%	100.0%	0.0%	17.4%	15.5%	30.6%	22.2%	19.4%	0.0%	48.1%	39.6%
Active	New Generation	9.9%	39.8%	2.2%	6.7%	0.0%	23.4%	63.3%	100.0%	1.9%	9.1%	24.5%	0.0%	0.0%	0.0%	0.0%	9.9%
	Upgrade	8.7%	47.7%	11.2%	12.5%	16.7%	46.2%	0.0%	100.0%	4.3%	12.1%	45.8%	0.0%	4.5%	50.0%	0.0%	25.0%

Table 12-22 shows the nameplate generating capacity of projects in the PJM generation queue by technology type and project classification. For example, the 383 new generation wind projects that have been withdrawn from the queue as of March 31, 2018, listed in Table 12-20 constitute 60,591.9 MW of nameplate capacity. The 528 new generation and upgrade natural gas CT projects that have been withdrawn in the same time period constitute 178,221.4 MW of nameplate capacity.

Table 12-22 Status of all generation capacity (MW) in the PJM generation queue: January 1997 through March 2018

		Project MW																
Project Status	Project Classification	Battery	Combined Cycle	CT - Natural Gas	CT - Other	Diesel	Diesel - Landfill Gas	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	Solar	Steam - Biomass	Steam - Coal	Steam - Natural Gas	Steam - Oil	Wind	Total
In Service	New Generation	161.4	3,631.2	24,812.4	50.0	62.0	6.2	1.9	0.0	572.9	9.0	1,261.4	223.8	1,378.0	16.5	607.0	7,057.9	39,851.6
	Upgrade	36.4	516.5	6,548.2	547.5	32.8	1.1	0.0	0.0	627.8	3,912.8	19.4	60.7	838.5	70.0	125.8	33.7	13,371.1
Under Construction	New Generation	42.1	10,910.6	463.2	0.0	0.0	21.3	0.0	0.0	23.1	0.0	338.3	0.0	0.0	590.0	0.0	2,661.9	15,050.5
	Upgrade	32.0	864.0	466.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	62.5	48.0	0.0	0.0	0.0	1,472.6
Suspended	New Generation	43.3	5,428.0	928.6	0.0	0.0	39.8	0.0	0.0	0.0	0.0	378.0	16.0	0.0	0.0	0.0	3,561.7	10,395.4
	Upgrade	23.0	196.1	233.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	552.1
Withdrawn	New Generation	1,320.7	18,872.0	171,449.6	843.8	63.9	339.3	1.7	0.0	1,986.9	8,161.0	18,679.2	1,027.7	33,511.6	34.2	1,721.0	60,591.9	318,604.5
	Upgrade	301.1	2,019.3	6,771.8	24.0	13.0	6.0	0.9	0.0	57.1	916.0	496.1	37.1	815.0	0.0	589.0	386.3	12,432.8
Active	New Generation	206.9	30,304.3	2,549.0	14.0	0.0	161.1	4.0	20.0	15.0	28.0	19,762.2	0.0	0.0	0.0	0.0	11,413.2	64,477.6
	Upgrade	30.0	3,930.4	2,005.6	20.0	4.0	9.2	0.0	34.0	5.5	111.4	1,567.5	0.0	60.0	94.0	0.0	359.7	8,231.2
Total Projects	New Generation	1,774.3	69,146.1	200,202.7	907.8	125.9	567.7	7.6	20.0	2,597.9	8,198.0	40,419.1	1,267.5	34,889.6	640.7	2,328.0	85,286.6	448,379.6
	Upgrade	422.5	7,526.3	16,024.7	591.5	49.8	16.3	0.9	34.0	690.4	4,940.2	2,083.0	160.3	1,761.5	164.0	714.8	879.6	36,059.8

Table 12-23 shows the project MW that have entered the PJM generation queue by fuel type and year of entry. In 2015 and 2016, natural gas, wind, and solar projects accounted for the majority of all new projects entering the generation queue. The increase in solar projects entering the queue in 2016 from 2015 was primarily a result of new projects in Dominion. The increase in solar projects entering the queue in 2017 was primarily a result of new projects in AEP.

Table 12-23 Queue project MW by fuel type and queue entry year: January 1997 through March 2018

	Battery	Combined Cycle	CT - Natural Gas	CT - Other	Diesel	Diesel - Landfill Gas	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	Solar	Steam - Biomass	Steam - Coal	Steam - Natural Gas	Steam - Oil	Wind	Total
1997	0.0	0.0	4,469.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	6.0	0.0	315.0	0.0	4,840.0
1998	0.0	0.0	8,781.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,781.0
1999	0.0	0.0	31,834.8	525.0	0.0	0.0	0.0	0.0	196.0	45.0	0.0	0.0	47.0	0.0	0.0	115.4	32,763.2
2000	0.0	0.0	21,650.8	0.0	0.0	0.0	0.0	0.0	0.0	95.0	0.0	0.0	37.0	0.0	31.5	95.6	21,909.9
2001	0.0	0.0	25,701.3	0.0	0.0	0.0	0.0	0.0	107.0	90.0	0.0	0.0	1,244.6	0.0	0.0	252.9	27,395.8
2002	0.0	0.0	4,248.7	0.0	23.3	0.0	0.0	0.0	293.0	236.0	0.0	0.0	1,895.0	0.0	0.0	790.9	7,486.9
2003	0.0	0.0	2,428.7	0.0	8.0	0.0	0.0	0.0	2.0	0.0	0.0	165.0	522.0	0.0	0.0	1,002.9	4,128.6
2004	0.0	0.0	3,708.9	11.0	55.5	0.0	0.0	0.0	0.0	1,911.0	0.0	0.0	1,187.0	0.0	0.0	1,613.7	8,487.1
2005	0.0	0.0	7,137.6	20.0	30.0	0.0	0.0	0.0	514.2	242.0	0.0	25.0	6,360.0	0.0	251.0	6,020.0	20,599.9
2006	0.0	440.0	4,312.1	0.0	7.5	0.0	0.0	0.0	159.0	6,894.0	0.0	314.9	9,586.0	0.0	600.0	7,650.7	29,964.2
2007	0.0	256.0	15,113.8	116.0	4.0	0.0	0.0	0.0	271.4	368.0	3.3	32.4	9,078.0	0.0	211.9	18,525.6	43,980.4
2008	121.0	930.0	25,306.2	423.8	0.0	0.0	0.0	0.0	1,254.5	105.0	66.3	189.8	1,198.0	0.0	1,113.0	11,199.7	41,907.3
2009	34.0	0.0	5,613.8	185.0	18.0	3.0	0.0	0.0	133.9	1,933.8	636.5	148.0	1,273.0	0.0	64.0	6,672.6	16,715.6
2010	104.4	680.2	8,751.8	58.0	2.4	0.0	0.0	0.0	132.6	426.0	3,697.1	220.0	64.0	0.0	7.9	9,908.4	24,052.8
2011	24.1	2,835.0	17,612.4	126.5	14.0	0.0	0.0	0.0	30.0	182.0	2,022.9	109.0	357.0	0.0	0.0	5,576.4	28,889.3
2012	142.6	4,966.6	13,579.9	0.0	0.0	0.0	0.0	0.0	11.8	369.0	286.6	143.1	1,837.0	0.0	42.5	1,529.8	22,908.8
2013	217.4	3,501.0	8,276.4	0.0	0.0	0.0	0.0	0.0	89.4	102.0	231.7	44.7	158.0	40.0	5.0	1,407.9	14,073.4
2014	226.9	9,417.8	3,928.5	0.0	0.0	29.1	0.0	20.0	60.5	0.0	1,445.7	35.9	1,730.5	34.2	401.0	1,763.7	19,093.8
2015	546.9	27,539.1	1,331.8	0.0	13.0	347.0	2.3	34.0	0.0	0.0	2,931.6	0.0	47.0	606.5	0.0	2,160.6	35,559.7
2016	111.1	18,869.0	1,392.0	20.0	0.0	62.4	3.4	0.0	12.5	50.3	11,773.5	0.0	10.0	107.0	0.0	3,467.5	35,878.7
2017	24.6	5,503.3	778.1	0.0	0.0	142.5	2.9	0.0	20.5	39.1	13,941.9	0.0	14.0	17.0	0.0	5,602.0	26,086.0
2018	643.8	1,734.4	269.8	14.0	0.0	0.0	0.0	0.0	0.0	0.0	5,464.9	0.0	0.0	0.0	0.0	810.0	8,936.9
Total	2,196.8	76,672.4	216,227.4	1,499.3	175.7	584.0	8.5	54.0	3,288.3	13,138.2	42,502.0	1,427.8	36,651.1	804.7	3,042.8	86,166.2	484,439.4

Table 12-24 shows the MW in Table 12-22 by share by classification as new generation or upgrade. Within a fuel type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 71.0 percent of wind projects classified as new generation have been withdrawn from the queue between January 1, 1997, and March 31, 2018.

Table 12-24 Status of all generation queue projects as percent of total MW in project classification: January 1997 through March 2018

		Percent of Total Projects by Classification															
Project Status	Project Classification	Battery	Combined Cycle	CT - Natural Gas	CT - Other	Diesel	Diesel - Landfill Gas	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	Solar	Steam - Biomass	Steam - Coal	Steam - Natural Gas	Steam - Oil	Wind
In Service	New Generation	9.1%	5.3%	12.4%	5.5%	49.2%	1.1%	25.5%	0.0%	22.1%	0.1%	3.1%	17.7%	3.9%	2.6%	26.1%	8.3%
	Upgrade	8.6%	6.9%	40.9%	92.6%	65.8%	6.7%	0.0%	0.0%	90.9%	79.2%	0.9%	37.9%	47.6%	42.7%	17.6%	3.8%
Under Construction	New Generation	2.4%	15.8%	0.2%	0.0%	0.0%	3.8%	0.0%	0.0%	0.9%	0.0%	0.8%	0.0%	0.0%	92.1%	0.0%	3.1%
	Upgrade	7.6%	11.5%	2.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	39.0%	2.7%	0.0%	0.0%	0.0%
Suspended	New Generation	2.4%	7.9%	0.5%	0.0%	0.0%	7.0%	0.0%	0.0%	0.0%	0.0%	0.9%	1.3%	0.0%	0.0%	0.0%	4.2%
	Upgrade	5.4%	2.6%	1.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	11.4%
Withdrawn	New Generation	74.4%	27.3%	85.6%	92.9%	50.8%	59.8%	22.1%	0.0%	76.5%	99.5%	46.2%	81.1%	96.1%	5.3%	73.9%	71.0%
	Upgrade	71.3%	26.8%	42.3%	4.1%	26.1%	36.8%	100.0%	0.0%	8.3%	18.5%	23.8%	23.1%	46.3%	0.0%	82.4%	43.9%
Active	New Generation	11.7%	43.8%	1.3%	1.5%	0.0%	28.4%	52.4%	100.0%	0.6%	0.3%	48.9%	0.0%	0.0%	0.0%	0.0%	13.4%
	Upgrade	7.1%	52.2%	12.5%	3.4%	8.0%	56.4%	0.0%	100.0%	0.8%	2.3%	75.3%	0.0%	3.4%	57.3%	0.0%	40.9%

Combustion Turbine - Natural Gas Project Analysis

Table 12-25 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997 through March 31, 2018, by zone. Of the 69 combustion turbine natural gas projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 31 projects (44.9 percent) are located within AEP, ComEd and APS.

Table 12-25 Status of all natural gas generation queue projects: January 1997 through March 2018

		Number of Projects																				
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	12	10	11	3	7	8	1	2	0	14	14	0	11	9	7	10	10	15	18	0	162
	Upgrade	8	10	8	3	2	11	6	0	0	30	14	0	5	3	11	5	5	10	28	0	159
Under Construction	New Generation	0	1	0	0	0	0	0	0	1	1	0	0	0	0	1	0	1	1	0	0	6
	Upgrade	0	1	0	0	0	2	0	0	0	0	0	0	1	0	2	0	1	0	2	0	9
Suspended	New Generation	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0	4	0	0	0	0	7
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	0	0	2
Withdrawn	New Generation	23	24	51	12	8	15	0	1	3	24	17	2	21	27	37	44	34	49	57	2	451
	Upgrade	8	3	5	5	0	4	0	1	0	7	4	0	5	8	0	4	3	6	14	0	77
Active	New Generation	1	1	0	0	1	4	0	0	0	2	0	1	0	0	0	2	0	1	1	0	14
	Upgrade	2	1	5	1	0	14	0	0	0	5	1	0	0	0	0	2	0	0	0	0	31
Total Projects	New Generation	37	37	63	15	16	27	1	3	4	41	31	3	32	36	45	60	45	66	76	2	640
	Upgrade	18	15	18	9	2	31	6	1	0	42	19	0	12	11	13	11	10	16	44	0	278

Table 12-26 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation queues from January 1, 1997 through March 31, 2018, by zone. Of the 6,645.5 MW of combustion turbine natural gas projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 2,782.7 MW (41.9 percent) are located within AEP, ComEd and APS.

Table 12-26 Status of all natural gas generation capacity (MW) in the PJM generation queue: January 1997 through March 2018

		Project MW																				
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	1,028.4	1,647.9	1,721.3	26.5	139.5	678.0	10.0	24.8	0.0	4,074.0	1,767.0	0.0	2,086.7	2,142.2	2,469.0	431.9	850.5	2,890.6	2,824.2	0.0	24,812.4
	Upgrade	265.7	239.0	811.8	44.0	6.5	844.0	60.0	0.0	0.0	1,478.1	196.0	0.0	224.0	45.7	784.2	34.3	121.1	333.9	1,059.8	0.0	6,548.2
Under Construction	New Generation	0.0	3.2	0.0	0.0	0.0	0.0	0.0	0.0	205.0	8.0	0.0	0.0	0.0	0.0	0.5	0.0	19.5	227.0	0.0	0.0	463.2
	Upgrade	0.0	6.0	0.0	0.0	0.0	32.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	132.0	0.0	64.5	0.0	231.0	0.0	466.1
Suspended	New Generation	235.0	585.0	19.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	88.7	0.0	0.0	0.0	0.0	928.6
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0	0.0	0.0	0.0	33.0	0.0	0.0	0.0	233.0
Withdrawn	New Generation	6,933.8	6,813.9	14,404.5	5,362.7	3,122.1	3,167.7	0.0	134.5	684.2	10,550.0	4,838.0	377.8	9,817.4	11,967.4	20,460.0	14,737.4	20,418.2	16,086.4	21,566.8	6.9	171,449.6
	Upgrade	124.8	636.0	521.9	111.0	0.0	14.5	0.0	36.0	0.0	300.0	668.0	0.0	156.8	1,733.2	0.0	51.6	85.0	483.2	1,849.9	0.0	6,771.8
Active	New Generation	230.0	394.0	0.0	0.0	144.6	430.0	0.0	0.0	0.0	99.2	0.0	75.0	0.0	0.0	0.0	481.3	0.0	19.9	675.0	0.0	2,549.0
	Upgrade	232.0	19.0	120.0	70.0	0.0	1,173.0	0.0	0.0	0.0	95.0	60.0	0.0	0.0	0.0	0.0	236.6	0.0	0.0	0.0	0.0	2,005.6
Total Projects	New Generation	8,427.2	9,444.0	16,145.7	5,389.2	3,406.2	4,275.7	10.0	159.3	889.2	14,731.2	6,605.0	452.8	11,904.1	14,109.6	22,929.5	15,739.2	21,288.2	19,223.9	25,066.0	6.9	200,202.7
	Upgrade	622.5	900.0	1,453.7	225.0	6.5	2,064.1	60.0	36.0	0.0	1,873.1	924.0	0.0	580.8	1,778.9	916.2	322.5	303.6	817.1	3,140.7	0.0	16,024.7

Wind Project Analysis

Table 12-27 shows the status of all wind generation projects that entered PJM generation queues from January 1, 1997 through March 31, 2018, by zone. Of the 80 wind projects to achieve in service status, 71 projects (88.8 percent) are located within ComEd, AEP, APS and PENELEC. Of the 117 wind projects currently active, suspended or under construction in the PJM generation queue, 85 projects (72.6 percent) are located within ComEd, AEP, APS and PENELEC.

Table 12-27 Status of all wind generation queue projects: January 1997 through March 2018

		Number of Projects																				
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	1	12	11	0	0	17	0	0	0	0	0	0	0	0	0	20	0	4	0	0	65
	Upgrade	0	0	3	0	0	2	0	0	0	0	0	0	0	0	0	6	0	4	0	0	15
Under Construction	New Generation	0	4	4	0	0	4	0	0	1	5	0	0	0	0	1	1	1	1	0	0	22
	Upgrade	0	1	1	0	0	2	0	0	0	0	0	0	1	0	2	0	1	0	2	0	10
Suspended	New Generation	0	9	3	1	0	1	1	0	0	1	0	0	0	0	0	2	0	1	0	0	19
	Upgrade	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Withdrawn	New Generation	38	109	90	18	8	109	14	1	3	40	26	3	21	27	37	105	34	91	58	2	834
	Upgrade	9	3	11	5	0	7	0	1	0	9	4	0	5	8	0	9	3	8	14	0	96
Active	New Generation	1	20	4	3	0	16	0	0	0	2	2	0	0	0	0	1	0	4	0	0	53
	Upgrade	1	0	4	0	0	5	0	0	0	0	0	0	0	0	0	2	0	0	0	0	12
Total Projects	New Generation	40	154	112	22	8	147	15	1	4	48	28	3	21	27	38	129	35	101	58	2	993
	Upgrade	10	5	19	5	0	16	0	1	0	9	4	0	6	8	2	17	4	12	16	0	134

Table 12-28 shows the wind project capacity in MW of all wind generation projects that have entered the PJM generation queue from January 1, 1997 through March 31, 2018, by zone. Of the 7,091.6 MW of wind generation capacity to achieve the in service status, 6,857.6 MW (96.7 percent) of nameplate capacity is located within ComEd, AEP, APS and PENELEC. Of the 18,096.5 MW of wind generation capacity currently active, suspended or under construction in the PJM generation queue, 14,606.8 MW of generation capacity (80.7 percent) is located within ComEd, AEP, APS and PENELEC.

Table 12-28 Status of all wind generation capacity (MW) in the PJM generation queue: January 1997 through March 2018

		Project MW																				
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	7.5	2,438.7	1,004.0	0.0	0.0	2,413.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	995.0	0.0	199.2	0.0	0.0	7,057.9
	Upgrade	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	0.0	0.0	6.4	0.0	27.3	0.0	0.0	33.7
Under Construction	New Generation	0.0	550.0	348.6	0.0	0.0	978.5	0.0	0.0	0.0	714.8	0.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	2,661.9
	Upgrade	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	1,730.0	375.1	500.0	0.0	500.0	100.0	0.0	0.0	76.6	0.0	0.0	0.0	0.0	0.0	180.0	0.0	100.0	0.0	0.0	3,561.7
	Upgrade	0.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0
Withdrawn	New Generation	3,626.4	15,820.6	2,935.1	645.6	0.0	22,314.2	2,028.0	0.0	0.0	2,361.5	2,565.0	150.3	0.0	0.0	0.0	5,059.0	0.0	3,066.3	20.0	0.0	60,591.9
	Upgrade	0.0	0.0	100.0	0.0	0.0	5.7	0.0	0.0	0.0	82.0	0.0	0.0	0.0	0.0	0.0	192.6	0.0	6.0	0.0	0.0	386.3
Active	New Generation	20.0	5,629.5	357.0	816.1	0.0	3,295.5	0.0	0.0	0.0	226.6	499.6	0.0	0.0	0.0	0.0	138.0	0.0	431.1	0.0	0.0	11,413.2
	Upgrade	5.0	0.0	105.7	0.0	0.0	178.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.8	0.0	0.0	0.0	0.0	359.7
Total Projects	New Generation	3,653.9	26,168.8	5,019.8	1,961.7	0.0	29,501.6	2,128.0	0.0	0.0	3,379.5	3,064.6	150.3	0.0	0.0	0.0	6,442.0	0.0	3,796.6	20.0	0.0	85,286.6
	Upgrade	5.0	100.0	205.7	0.0	0.0	183.9	0.0	0.0	0.0	82.0	0.0	0.0	0.0	0.0	0.0	269.7	0.0	33.3	0.0	0.0	879.6

Solar Project Analysis

Table 12-29 shows the status of all solar generation projects that have entered the PJM generation queue from January 1, 1997 through March 31, 2018, by zone. Of a total of 1,451 solar projects ever to enter the PJM generation queue, 532 projects (36.7 percent) have been located in JCPL, AECO and PSEG, all zones in New Jersey. Of these three zones, AECO has the lowest completion rates for new generation and upgrade solar projects (with 4.0 percent of solar projects classified as new generation or upgrades in AECO either in service or under construction). Of these three zones, PSEG has the highest completion rates (with 36.6 percent of solar projects classified as either new generation or upgrades in PSEG either in service or under construction).

The number of new generation solar projects currently active, suspended or under construction is also highly concentrated in several zones. Of the 396 new generation solar projects that are active, suspended or under construction, 134 projects (33.8 percent) are located in Dominion. Of the 396 new generation solar projects that are active, suspended or under construction, 73 projects (18.4 percent) are located in AEP.

Table 12-29 Status of all solar generation queue projects: January 1997 through March 2018

		Number of Projects																				
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	7	4	4	0	1	1	1	0	0	16	9	0	39	0	1	0	0	2	38	0	123
	Upgrade	0	0	0	0	0	0	0	0	0	2	8	0	6	0	0	0	0	0	0	0	16
Under Construction	New Generation	0	1	1	0	2	0	1	0	0	2	5	0	7	0	0	0	0	0	7	0	26
	Upgrade	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	5	17	0	0	0	1	0	0	1	0	0	5	1	0	1	0	0	1	0	32
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	158	60	55	8	10	17	10	11	0	123	105	3	167	12	6	11	10	27	67	0	860
	Upgrade	1	2	0	0	0	0	0	0	0	9	1	0	8	0	0	0	0	0	1	0	22
Active	New Generation	8	67	13	5	0	22	9	3	1	131	45	5	2	5	1	3	6	2	9	1	338
	Upgrade	0	4	2	1	0	1	0	2	1	18	1	0	1	1	0	0	0	1	0	0	33
Total Projects	New Generation	173	137	90	13	13	40	22	14	1	273	164	8	220	18	8	15	16	31	122	1	1,379
	Upgrade	**1**	**6**	**2**	**1**	**0**	**1**	**0**	**2**	**1**	**29**	**11**	**0**	**15**	**1**	**0**	**0**	**0**	**1**	**1**	**0**	**72**

Table 12-30 shows the status of all solar generation project MW that have entered the PJM generation queue from January 1, 1997 through March 31, 2018, by zone. Of a total of 42,502.0 MW of solar nameplate capacity ever to enter the PJM generation queue, 4,335.2 MW (10.2 percent) have been located in JCPL, AECO and PSEG, all of which are zones in New Jersey. Solar projects in Dominion have accounted for 17,469.3 MW (41.1 percent) of all solar project nameplate capacity in the PJM queue from January 1, 1997 through March 31, 2018. Solar projects in DPL have accounted for 2,986.0 MW or 7.0 percent of all solar project nameplate capacity in the PJM queue from January 1, 1997 through March 31, 2018.

Table 12-30 Current status of all solar generation capacity (MW) in the PJM generation queue: January 1997 through March 2018

		Project MW																				
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	57.3	14.7	53.0	0.0	1.1	9.0	2.5	0.0	0.0	529.2	118.4	0.0	266.9	0.0	3.3	0.0	0.0	15.0	191.0	0.0	1,261.4
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.1	0.0	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.4
Under Construction	New Generation	0.0	20.0	10.0	0.0	22.0	0.0	3.4	0.0	0.0	100.0	43.0	0.0	107.4	0.0	0.0	0.0	0.0	0.0	32.6	0.0	338.3
	Upgrade	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	59.9	221.5	0.0	0.0	0.0	20.0	0.0	0.0	5.0	0.0	0.0	49.1	3.0	0.0	13.5	0.0	0.0	6.0	0.0	378.0
	Upgrade	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	1,664.3	2,862.8	1,244.4	216.1	31.3	963.8	300.5	259.4	0.0	6,635.1	1,419.9	189.9	1,348.8	467.0	51.4	114.3	174.6	283.7	451.9	0.0	18,679.2
	Upgrade	10.0	106.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	355.0	0.0	0.0	23.8	0.0	0.0	0.0	0.0	0.0	1.3	0.0	496.1
Active	New Generation	42.3	5,025.6	688.8	826.0	0.0	1,071.5	739.5	215.0	11.7	8,848.2	1,384.7	330.0	9.1	190.0	18.0	150.3	92.8	30.0	48.7	40.0	19,762.2
	Upgrade	0.0	337.0	75.0	20.0	0.0	0.0	0.0	85.0	8.3	993.7	20.0	0.0	8.5	20.0	0.0	0.0	0.0	0.0	0.0	0.0	1,567.5
Total Projects	New Generation	1,763.9	7,983.1	2,217.7	1,042.1	54.4	2,044.3	1,065.9	474.4	11.7	16,117.5	2,966.0	519.9	1,781.2	660.0	72.7	278.1	267.3	328.7	730.3	40.0	40,419.1
	Upgrade	10.0	443.0	75.0	20.0	0.0	0.0	0.0	85.0	8.3	1,351.8	20.0	0.0	48.6	20.0	0.0	0.0	0.0	0.0	1.3	0.0	2,083.0

Regional Transmission Expansion Plan (RTEP)

Authorized TEAC Transmission Upgrades

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals are periodically presented to the PJM Board of Managers for authorization.

- On February 14, 2018, the PJM Board of Managers authorized an additional $397.0 million in transmission upgrades and additions. The approved projects include local planning criteria projects in the PSEG and Dominion zones, end of life projects in the Dominion Zone and additional equipment upgrades necessary to relieve congestion in the BGE, PPL and DEOK zones.

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 are currently three backbone projects under development, Surry Skiffes Creek 500kV, and the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV.[26]

Market Efficiency Process[27]

PJM's Regional Transmission Expansion Plan (RTEP) process includes a market efficiency analysis. The purpose of the market efficiency analysis is: to determine which reliability based enhancements have economic benefit if accelerated; to identify new transmission enhancements that result in economic benefits; and to identify economic benefits associated with modification to existing RTEP reliability based enhancements that when modified would relieve one or more economic constraints. PJM identifies the economic benefit of proposed transmission projects by conducting production cost analyses.[28]

PJM presents all of the RTEP market efficiency enhancements to the TEAC Committee for review and comment. Subsequent to TEAC review, PJM addresses the TEAC review and presents the final RTEP market efficiency plan to the PJM Board, along with the advice, comments, and recommendations of the TEAC Committee, for Board approval.

To be included in the RTEP recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic based enhancement or expansion must meet a benefit/cost ratio threshold of at least 1.25:1. The benefit/cost ratio is the ratio of the present value of the total annual benefit for 15 years by the present value of the total annual cost for each of the first 15 years of the life of the enhancement or expansion.

The market efficiency process is comprised of a 12 month cycle and a 24 month cycle, both of which begin and end on the calendar year. The 12 month cycle is used for analysis of modifications and accelerations to approved RTEP projects only. The 24 month cycle is used for analysis of new economic transmission upgrades for years five through 15. This long-term proposal window takes place concurrent with the long-term proposal window for reliability projects. [29]

Through March 31, 2018, PJM has completed two market efficiency cycles. In the first cycle, PJM received 92 proposals for 11 identified issues. In the second market efficiency cycle, PJM received 96 proposals for four identified issues.

Supplemental Projects

Supplemental projects are "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as

26 See PJM. "*2017 RTEP Process Scope and Input Assumptions White Paper*," P 25. <http://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en>.

27 The material in this section is based in part on the PJM Manual 14B: PJM Region Transmission Planning Process. See PJM. "*PJM Manual 14B: PJM Region Transmission Planning Process*," Rev. 40 (Oct. 26, 2017) <http://www.pjm.com/-/media/documents/manuals/m14b.ashx?la=en>.

28 See PJM. "*PJM Regional Transmission Expansion Plan: 2016*," (February 28, 2017). <http://www.pjm.com/-/media/library/reports-notices/2016-rtep/2016-rtep-books-1-3.ashx?la=en>.

29 See PJM. "*PJM Market Efficiency Modeling Practices*," (February 2, 2017). <http://www.pjm.com/-/media/planning/rtep-dev/market-efficiency/pjm-market-efficiency-modeling-practices.ashx?la=en>.

inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[30] Supplemental projects are funded wholly by the Transmission Owner and no PJM approval is needed. Supplemental projects addressed two of the four issues identified in the most recent market efficiency cycle. Because supplemental projects are considered by transmission owners to be outside the scope of FERC Order No. 1000, supplemental projects may be considered noncompetitive.

The MMU is concerned with the impact of supplemental projects on the market efficiency process. It is not clear how a supplemental project can be used to resolve market efficiency projects that have been identified based on a cost/benefit analysis and why such a project should not be subject to competition. The MMU recommends that PJM limit the scope of supplemental projects that can obtain exceptions to the Order No. 1000 process to ensure maximum competition.

PJM MISO Interregional Targeted Market Efficiency Process (TMEP)

PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commissions concerns about interregional coordination along the PJM-MISO seam, called the Targeted Market Efficiency Process (TMEP).[31]

The allocation of costs to each RTO for TMEPs will be in proportion to the benefits received.[32]

On November 2, 2017, PJM submitted a compliance filing including additional revisions the MISO-PJM JOA to include stakeholder feedback in the TMEP project selection process.[33] [34]

The first TMEP analysis included the investigation of congestion on 50 market to market flowgates. The study resulted in the evaluation of 13 potential upgrades, resulting in the recommendation of five TMEP projects. The five projects address $59 million in historical congestion, with a TMEP benefit of $99.6 million. The projects have a total cost of $20 million, with a 5.0 average benefit/cost ratio. PJM and MISO presented the five recommended projects to their boards in December, 2017, and both boards approved all five projects.[35]

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.[36] When one of the reportable transmission facilities needs to be taken out of service, the TO is required to submit an outage request as early as possible. The specific timeline is shown in Table 12-32.[37]

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.[38] Table 12-31 shows that 76.5 percent of the requested outages were planned for less than or equal to five days and 7.5 percent of requested outages were planned for greater than 30 days in the 2017/2018 planning period. It also shows that 76.9 percent of the requested outages were planned for less than or equal to five days and 7.0 percent of requested outages were planned for greater than 30 days in the 2016/2017 planning period.

30 See PJM. "*Transmission Construction Status*," (January 23, 2018) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.
31 See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000 (December 30, 2016).
32 See *PJM Interconnection, L.L.C*, Docket No. ER17-729-000 (December 30, 2016).
33 See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000, ER17-721-000 and ER17-729-000 (Not Consolidated) (November 2, 2017).
34 161 FERC ¶ 61,005 (2017). *Order accepting filings subject to condition.*
35 See PJM. "*MISO PJM IPSAC*," (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.
36 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), Rev. 13 (September 29, 2017).
37 See PJM. "Manual 3: Transmission Operations," Rev. 52 (Dec. 22, 2017), at 65–66.
38 *Id.* at 70.

All of the outage data in this section except in the analysis for the day-ahead market are for outages scheduled to occur in the planning periods 2016/2017 and 2017/2018, regardless of when they were initially submitted.[39] The outage data in the analysis for the day-ahead market are for outages scheduled to occur from January 1, 2015, through March 31, 2018.

Table 12-31 Transmission facility outage request summary by planned duration: planning periods 2016/2017 and 2017/2018

	2016/2017		2017/2018	
Planned Duration (Days)	Outage Requests	Percent	Outage Requests	Percent
<=5	16,440	76.9%	15,111	76.5%
>5 & <=30	3,448	16.1%	3,165	16.0%
>30	1,490	7.0%	1,489	7.5%
Total	21,378	100.0%	19,765	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 and outage planned duration. The received status can be On Time or Late, as defined in Table 12-32.[40]

The purpose of the rules defined in Table 12-32 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.[41]

39 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.
40 See PJM. "Manual 3: Transmission Operations," Rev. 52 (Dec. 22, 2017) at 65–66.
41 See "*Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures*," Docket No. EL01-122-000 (November 2, 2001).

Table 12-32 PJM transmission facility outage request received status definition

Planned Duration (Calendar Days)	Request Submitted	Received Status
<=5	Before the first of the month one month prior to the starting month of the outage	On Time
	After or on the first of the month one month prior to the starting month of the outage	Late
> 5 & <=30	Before the first of the month six months prior to the starting month of the outage	On Time
	After or on the first of the month six months prior to the starting month of the outage	Late
>30	The earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage	On Time
	After or on the earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage	Late

Table 12-33 shows a summary of requests by received status. In the 2017/2018 planning period, 44.9 percent of outage requests received were late. In the 2016/2017 planning period, 50.2 percent of outage requests received were late.

Table 12-33 Transmission facility outage request summary by received status: planning periods 2016/2017 and 2017/2018

	2016/2017				2017/2018			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	8,471	7,969	16,440	48.5%	8,684	6,427	15,111	42.5%
>5 & <=30	1,667	1,781	3,448	51.7%	1,641	1,524	3,165	48.2%
>30	515	975	1,490	65.4%	570	919	1,489	61.7%
Total	10,653	10,725	21,378	50.2%	10,895	8,870	19,765	44.9%

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 late unless the request is an emergency.

Outages with emergency status will be approved even if submitted late 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.[42] Table 12-34 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the 2017/2018 planning period, 11.2 percent were for emergency outages. Of all outage requests scheduled to occur in the 2016/2017 planning period, 13.2 percent were for emergency outages.

Table 12-34 Transmission facility outage request summary by emergency: planning periods 2016/2017 and 2017/2018

	2016/2017				2017/2018			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	2,186	14,254	16,440	13.3%	1,693	13,418	15,111	11.2%
>5 & <=30	433	3,015	3,448	12.6%	327	2,838	3,165	10.3%
>30	199	1,291	1,490	13.4%	203	1,286	1,489	13.6%
Total	2,818	18,560	21,378	13.2%	2,223	17,542	19,765	11.2%

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 are not expected to cause congestion on the PJM system and do not jeopardize the reliability of the PJM system. Each outage is studied and if it is expected to cause a constraint to exceed a limit, PJM will flag the outage ticket as "congestion expected."[43]

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 12-35 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the 2017/2018 planning period, 7.5 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.1 percent (45 out of 1,475) were denied by PJM in the 2017/2018 planning period and 17.4 percent (257 out of 1,475) were cancelled (Table 12-37). Of all outage requests submitted to occur in the 2016/2017 planning period, 8.9 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 4.1 percent (77 out of 1,893) were denied by PJM in the 2016/2017 planning period and 19.0 percent (360 out of 1,893) were cancelled (Table 12-37).

Table 12-35 Transmission facility outage request summary by congestion: planning periods 2016/2017 and 2017/2018

	2016/2017				2017/2018			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	1,389	15,051	16,440	8.4%	981	14,130	15,111	6.5%
>5 & <=30	373	3,075	3,448	10.8%	346	2,819	3,165	10.9%
>30	131	1,359	1,490	8.8%	148	1,341	1,489	9.9%
Total	1,893	19,485	21,378	8.9%	1,475	18,290	19,765	7.5%

Table 12-36 shows the outage requests summary by received status, congestion status and emergency status. In the 2017/2018 planning period, 33.7 percent of requests were submitted late and were nonemergency while 1.3 percent of requests (249 out of 19,765) were late, nonemergency, and expected to cause congestion. In the 2016/2017 planning period, 37.1 percent of request were submitted late and were nonemergency while 1.9 percent of requests (403 out of 21,378) were late, nonemergency, and expected to cause congestion.

42 PJM. "Manual 3: Transmission Operations," Rev. 52 (Dec. 22, 2017) at 81.
43 PJM added this definition to Manual 38 in February 2017. PJM. "Manual 38: Operations Planning," Rev. 11 (February 1, 2018) at 20.

Table 12-36 Transmission facility outage request summary by received status, emergency and congestion: planning periods 2016/2017 and 2017/2018

		2016/2017				2017/2018			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent	Congestion Expected	No Congestion Expected	Total	Percent
Late	Emergency	114	2,687	2,801	13.1%	81	2,119	2,200	11.1%
	Non Emergency	403	7,521	7,924	37.1%	249	6,421	6,670	33.7%
On Time	Emergency	2	15	17	0.1%	3	20	23	0.1%
	Non Emergency	1,374	9,262	10,636	49.8%	1,142	9,730	10,872	55.0%
Total		1,893	19,485	21,378	100.0%	1,475	18,290	19,765	100.0%

Once PJM processes an outage request, the outage request is labelled as Submitted, Received, Denied, Approved, Cancelled by Company, PJM Admin Closure, Revised, Active or Complete according to the processed stage of a request.[44] Table 12-37 shows the detailed process status for outage requests only for the outage requests that are expected to cause congestion. Status Submitted and status Received are in the In Process category and status Cancelled by Company and status PJM Admin Closure are in the Cancelled category in Table 12-37. Table 12-37 shows that of all the outage requests that were expected to cause congestion, 3.1 percent (45 out of 1,475) were denied by PJM in the 2017/2018 planning period, 60.3 percent were complete and 17.4 percent (257 out of 1,475) were cancelled. Of all the outage requests that were expected to cause congestion, 4.1 percent (77 out of 1,893) were denied by PJM in the 2016/2017 planning period, 72.0 percent were complete and 19.0 percent (360 out of 1,893) were cancelled.

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[45] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Table 12-37 shows that in the 2016/2017 planning period, many (69.5 percent or 280 out of 403) outages that were nonemergency, expected to cause congestion, and late transmission outages were approved and completed compared to (64.3 percent or 160 out of 249) in the 2017/2018 planning period. 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.

Table 12-37 Transmission facility outage requests that might cause congestion status summary: planning periods 2016/2017 and 2017/2018

		2016/2017						2017/2018					
Received Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	10	103	0	1	114	90.4%	11	69	1	0	81	85.2%
	Non Emergency	71	280	8	44	403	69.5%	40	160	34	14	249	64.3%
On Time	Emergency	0	1	0	0	2	50.0%	2	1	0	0	3	33.3%
	Non Emergency	279	979	74	32	1,374	71.3%	204	660	235	31	1,142	57.8%
Total		360	1,363	82	77	1,893	72.0%	257	890	270	45	1,475	60.3%

44 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2017).

45 OA Schedule 1 § 1.9.2.

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-38 is a summary of all the outage requests planned for the planning periods 2016/2017 and 2017/2018 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 the 2017/2018 planning period, 25.5 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 10.1 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2016/2017 planning period, 30.4 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 10.9 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

Table 12-38 Rescheduled and cancelled transmission outage request summary: planning periods 2016/2017 and 2017/2018

	2016/2017					2017/2018				
Planned Duration (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	16,440	3,470	21.1%	2,054	12.5%	15,111	2,634	17.4%	1,765	11.7%
>5 & <=30	3,448	2,022	58.6%	212	6.1%	3,165	1,564	49.4%	173	5.5%
>30	1,490	998	67.0%	54	3.6%	1,489	838	56.3%	55	3.7%
Total	21,378	6,490	30.4%	2,320	10.9%	19,765	5,036	25.5%	1,993	10.1%

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 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.[46] This rule allows a TO to reschedule within the same month with very little notice.

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.[47] 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 nine 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.

46 PJM. "Manual 3: Transmission Operations," Rev. 52 (Dec. 22, 2017) at 70.

47 *Id.*

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-32) 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 12-39 shows that there were 12,120 transmission equipment planned outages in the 2017/2018 planning period, of which 1,537 were planned outages longer than 30 days, and of which 241 or 2.0 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.

Table 12-39 Transmission outage summary: planning periods 2016/2017 and 2017/2018

		2016/2017		2017/2018	
Planned Duration (Days)	Divided into Shorter Periods	Number of Outages	Percent	Number of Outages	Percent
> 30	No	1,288	10.1%	1,296	10.7%
	Yes	247	1.9%	241	2.0%
<= 30		11,237	88.0%	10,583	87.3%
Total		12,772	100.0%	12,120	100.0%

Table 12-40 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 the 2017/2018 planning period, there would have been 28 outages with a combined duration longer than 30 days that were instead scheduled to occur as shorter outages within a period of more than 31 days and less than 62 days.

Table 12-40 Summary of potentially long duration (> 30 days) outages: planning periods 2016/2017 and 2017/2018

	2016/2017		2017/2018	
Planned Duration (Days)	Number of Outages	Percent	Number of Outages	Percent
<=31	4	1.6%	4	1.7%
>31 & <=62	28	11.3%	28	11.6%
>62 & <=93	14	5.7%	19	7.9%
>93	201	81.4%	190	78.8%
Total	247	100.0%	241	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 governing outage reporting is to ensure that outages are known with enough lead time prior to FTR Auctions so that market participants can understand market conditions and so that PJM can accurately model market conditions.

There are Long Term, Annual and Monthly Balance of Planning Period auctions in the FTR Market. For each type of auction, PJM includes a set of outages to be modeled.

Annual FTR Market

The Annual FTR Market includes the Annual ARR Allocation and the Annual FTR Auction. When determining transmission outages to be modeled in the simultaneous feasibility test used in the Annual FTR Market, PJM considers all outages with planned duration longer than or equal to two months and may consider outages with planned durations shorter than two months. PJM may exercise significant discretion in selecting outages to be modeled. PJM posts an FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[48]

48 PJM Financial Transmission Rights, "Annual ARR Allocation and FTR Auction Transmission Outage Modeling," <http://www.pjm.com/~/media/markets-ops/ftr/annual-ftr-auction/2017-2018/2017-2018-annual-outage-modeling.ashx> (February 21, 2017).

In the 2017/2018 planning period, 250 outage requests were included in the annual FTR market outage list and 19,515 outage requests were not included. In the 2016/2017 planning period, 249 outage requests were included in the annual FTR market outage list and 21,129 outage requests were not included. Table 12-41, Table 12-42, Table 12-43 and Table 12-44 show the summary information on the modeled outage requests and Table 12-45 and Table 12-46 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-41 Annual FTR market modeled transmission facility outage requests by received status: planning periods 2016/2017 and 2017/2018

	2016/2017				2017/2018			
Planned Duration	On Time	Late	Total	Percent	On Time	Late	Total	Percent
<2 weeks	10	1	11	4.4%	5	2	7	2.8%
>=2 weeks & <2 months	88	2	90	36.1%	88	9	97	38.8%
>=2 months	125	23	148	59.4%	125	21	146	58.4%
Total	223	26	249	100.0%	218	32	250	100.0%

Table 12-42 Annual FTR market modeled transmission facility outage requests by emergency and received status: planning periods 2016/2017 and 2017/2018

		2016/2017				2017/2018			
Received Status	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	10	10	100.0%	0	5	5	100.0%
	>=2 weeks & <2 months	0	88	88	100.0%	0	88	88	100.0%
	>=2 months	0	125	125	100.0%	0	125	125	100.0%
	Total	0	223	223	100.0%	0	218	218	100.0%
Late	<2 weeks	0	1	1	100.0%	0	2	2	100.0%
	>=2 weeks & <2 months	0	2	2	100.0%	0	9	9	100.0%
	>=2 months	2	21	23	91.3%	0	21	21	100.0%
	Total	2	24	26	92.3%	0	32	32	100.0%

Table 12-41 shows that 2.8 percent of the outage requests modeled in the Annual FTR Market for the 2017/2018 planning period had a planned duration of less than two weeks and that 12.8 percent of the outage requests (32 out of 250) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 4.4 percent of the outage requests modeled in the Annual FTR Market for the 2016/2017 planning period had a planned duration of less than two weeks and that 10.4 percent of the outage requests (26 out of 249) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

Table 12-42 shows the annual FTR market modeled outage requests summary by emergency status and received status. All the annual FTR market modeled outages expected to occur in the 2017/2018 planning period were nonemergency outages. Two of the modeled outages expected to occur in the 2016/2017 planning period were emergency outages.

PJM determines 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 12-43 shows a summary of requests by expected congestion and received status. Overall, 12.5 percent (4 out of 32) of all the annual FTR market modeled outages expected to occur in the 2017/2018 planning period and submitted late were expected to cause congestion. Of all the annual FTR market modeled outages expected to occur in the 2016/2017 planning period and submitted late, 11.5 percent (3 out of 26) were expected to cause congestion.

Table 12-43 Annual FTR market modeled transmission facility outage requests by congestion and received status: planning periods 2016/2017 and 2017/2018

		2016/2017				2017/2018			
Received Status	Planned Duration	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
On Time	<2 weeks	2	8	10	20.0%	2	3	5	40.0%
	>=2 weeks & <2 months	19	69	88	21.6%	25	63	88	28.4%
	>=2 months	29	96	125	23.2%	37	88	125	29.6%
	Total	50	173	223	22.4%	64	154	218	29.4%
Late	<2 weeks	0	1	1	0.0%	0	2	2	0.0%
	>=2 weeks & <2 months	0	2	2	0.0%	1	8	9	11.1%
	>=2 months	3	20	23	13.0%	3	18	21	14.3%
	Total	3	23	26	11.5%	4	28	32	12.5%

Table 12-44 shows that 29.9 percent of outage requests modeled in the annual FTR market for the 2017/2018 planning period and with a duration of two weeks or longer but shorter than two months were cancelled, compared to 35.6 percent for the 2016/2017 planning period. Table 12-44 also shows that 12.3 percent of outages requests modeled in the Annual FTR Market for the 2017/2018 planning period and with a duration of two months or longer were cancelled, compared to 20.9 percent for the 2016/2017 planning period.

Table 12-44 Annual FTR market modeled transmission facility outage requests by processed status: planning periods 2016/2017 and 2017/2018

		2016/2017		2017/2018	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	0	0.0%	0	0.0%
	Denied	0	0.0%	0	0.0%
	Approved	0	0.0%	0	0.0%
	Cancelled	1	9.1%	2	28.6%
	Active	0	0.0%	0	0.0%
	Completed	10	90.9%	5	71.4%
	Total	11	100.0%	7	100.0%
>=2 weeks & <2 months	In Progress	10	11.1%	18	18.6%
	Denied	0	0.0%	2	2.1%
	Approved	0	0.0%	2	2.1%
	Cancelled	32	35.6%	29	29.9%
	Active	0	0.0%	7	7.2%
	Completed	48	53.3%	39	40.2%
	Total	90	100.0%	97	100.0%
>=2 months	In Progress	23	15.5%	33	22.6%
	Denied	0	0.0%	0	0.0%
	Approved	0	0.0%	2	1.4%
	Cancelled	31	20.9%	18	12.3%
	Active	3	2.0%	36	24.7%
	Completed	91	61.5%	57	39.0%
	Total	148	100.0%	146	100.0%

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the 2017/2018 planning period, 250 outage requests were modeled and 19,515 outage requests were not modeled in the Annual FTR Market. In the 2016/2017 planning period, 249 outage requests were modeled and 21,129 outage requests were not modeled in the Annual FTR Market.

Table 12-45 shows that 16.3 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labelled On Time according to the rules, were submitted after the Annual FTR Auction bidding opening date for the 2017/2018 planning period compared to 18.3 percent in the 2016/2017 planning period.

Table 12-45 Transmission facility outage requests not modeled in Annual FTR Auction: planning periods 2016/2017 and 2017/2018

	2016/2017						2017/2018					
	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	1,485	7,989	84.3%	260	8,803	97.1%	1,370	8,188	85.7%	242	7,064	96.7%
>=2 weeks & <2 months	459	377	45.1%	152	953	86.2%	579	380	39.6%	119	890	88.2%
>=2 months	98	22	18.3%	186	345	65.0%	134	26	16.3%	211	312	59.7%
Total	2,042	8,388	80.4%	598	10,101	94.4%	2,083	8,594	80.5%	572	8,266	93.5%

Table 12-46 shows that 53.2 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were approved and completed in the 2017/2018 planning period. It also shows that 78.3 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were approved and completed in the 2016/2017 planning period.

Table 12-46 Late transmission facility outage requests not modeled in Annual FTR Auction and submitted after annual bidding opening date: planning periods 2016/2017 and 2017/2018

	2016/2017			2017/2018		
Planned Duration	Completed Outages	Total	Percent	Completed Outages	Total	Percent
<2 weeks	7,385	8,803	83.9%	5,542	7,064	78.5%
>=2 weeks & <2 months	834	953	87.5%	610	890	68.5%
>=2 months	270	345	78.3%	166	312	53.2%
Total	8,489	10,101	84.0%	6,318	8,266	76.4%

Although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the opening of bidding in the Annual FTR Auction, the rules have not functioned effectively because the rule has no direct connection to the date on which bidding opens for the Annual FTR Auction. By requiring all long-duration transmission outages to be submitted before February 1, PJM outage submission rules only prevent long-duration transmission outages from being submitted late. The rule does not address the situation in which long-duration transmission outages are submitted on time, but are rescheduled so that they are late. There is no rule to address the situation in which short-duration outages (duration <= 5 days) are submitted on time, but are changed to long-duration transmission outages after the outages are approved and active. The Annual FTR Auction model may consider transmission outages planned for longer than two weeks but less than two months. Those outages not only include long duration outages but also include outages shorter than 30 days. In those cases, PJM outage submission rules failed to prevent long duration transmission outages from being submitted late. The MMU recommends that PJM modify the rules to eliminate the approval of outage requests submitted or rescheduled after the opening of bidding in the Annual FTR Auction.

Monthly FTR Market

When determining transmission outages to be modeled in the simultaneous feasibility test used in the Monthly Balance of Planning Period FTR Auction, PJM considers all outages with planned duration longer than five days and may consider outages with planned durations shorter than or equal to five days. PJM may exercise significant discretion in selecting outages to be modeled. PJM posts an FTR outage list to the FTR webpage usually at least one week before the auction bidding opening day.[49] Table 12-47 and Table 12-48 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-49 and Table 12-50 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

Table 12-47 shows that on average, 30.0 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2017/2018 planning period. On average, 30.8 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2016/2017 planning period.

Table 12-47 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: planning periods 2016/2017 and 2017/2018

	2016/2017				2017/2018			
Month	On Time	Late	Total	Late Percent	On Time	Late	Total	Late Percent
Jun	170	94	264	35.6%	134	116	250	46.4%
Jul	67	57	124	46.0%	83	72	155	46.5%
Aug	77	63	140	45.0%	100	73	173	42.2%
Sep	367	129	496	26.0%	394	125	519	24.1%
Oct	542	195	737	26.5%	598	162	760	21.3%
Nov	365	172	537	32.0%	453	177	630	28.1%
Dec	289	130	419	31.0%	330	142	472	30.1%
Jan	162	90	252	35.7%	194	78	272	28.7%
Feb	162	89	251	35.5%	214	125	339	36.9%
Mar	310	132	442	29.9%	391	168	559	30.1%
Apr	395	162	557	29.1%				
May	411	165	576	28.6%				
Avg	276	123	400	30.8%	289	124	413	30.0%

Table 12-48 shows that on average, 19.4 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2017/2018 planning period. On average, 20.4 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2016/2017 planning period.

49 PJM Financial Transmission Rights, "2015/2016 Monthly FTR Auction Transmission Outage Modeling," <http://www.pjm.com/-/media/markets-ops/ftr/ftr-allocation/monthly-ftr-auctions/2015-2016-monthly-transmission-outages-that-may-cause-infeasibilities.ashx?la=en> (December 9, 2015).

Table 12-48 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: planning periods 2016/2017 and 2017/2018

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Cancelled Percent
2016/2017	Jun	18	3	5	51	1	53	133	264	19.3%
	Jul	10	12	2	19	0	41	40	124	15.3%
	Aug	9	1	2	31	0	52	45	140	22.1%
	Sep	47	4	11	85	0	165	184	496	17.1%
	Oct	75	5	19	172	0	196	270	737	23.3%
	Nov	46	1	10	104	0	162	214	537	19.4%
	Dec	25	4	11	87	0	66	226	419	20.8%
	Jan	35	0	7	60	0	75	75	252	23.8%
	Feb	22	2	4	42	1	87	93	251	16.7%
	Mar	48	2	9	94	0	120	169	442	21.3%
	Apr	55	2	7	101	1	154	237	557	18.1%
	May	26	1	18	134	0	119	278	576	23.3%
	Avg	35	3	9	82	0	108	164	400	20.4%
2017/2018	Jun	19	5	5	52	0	64	105	250	20.8%
	Jul	11	2	8	25	0	54	55	155	16.1%
	Aug	10	0	1	27	0	64	71	173	15.6%
	Sep	67	8	13	100	3	161	167	519	19.3%
	Oct	77	2	27	142	0	201	311	760	18.7%
	Nov	39	5	10	121	2	177	276	630	19.2%
	Dec	42	4	9	97	0	74	246	472	20.6%
	Jan	29	6	9	59	0	80	89	272	21.7%
	Feb	33	1	3	63	1	108	130	339	18.6%
	Mar	66	5	15	114	3	171	185	559	20.4%
	Avg	39	4	10	80	1	115	164	413	19.4%

Table 12-49 shows that on average, 9.6 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled On Time according to the rules, were submitted after the monthly FTR auction bidding opening dates in the 2017/2018 planning period, compared to 10.1 percent in the 2016/2017 planning period. On average, 70.7 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled Late according to the rules, were submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates in the 2017/2018 planning period, compared to 70.7 percent in the 2016/2017 planning period.

Table 12-49 Transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction: planning periods 2016/2017 and 2017/2018

	2016/2017						2017/2018					
	On Time			Late			On Time			Late		
	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
Jun	694	103	12.9%	335	895	72.8%	642	96	13.0%	305	852	73.6%
Jul	274	74	21.3%	251	698	73.6%	294	48	14.0%	245	608	71.3%
Aug	413	92	18.2%	259	733	73.9%	341	28	7.6%	211	651	75.5%
Sep	964	156	13.9%	292	772	72.6%	861	82	8.7%	256	599	70.1%
Oct	1,092	89	7.5%	430	901	67.7%	990	85	7.9%	346	867	71.5%
Nov	887	57	6.0%	389	832	68.1%	822	76	8.5%	365	791	68.4%
Dec	600	48	7.4%	340	723	68.0%	611	67	9.9%	324	693	68.1%
Jan	429	38	8.1%	243	592	70.9%	572	67	10.5%	287	745	72.2%
Feb	462	25	5.1%	301	674	69.1%	604	38	5.9%	341	699	67.2%
Mar	1,068	94	8.1%	357	806	69.3%	1,147	140	10.9%	342	800	70.1%
Apr	1,140	103	8.3%	340	789	69.9%						
May	1,142	155	12.0%	356	966	73.1%						
Avg	764	86	10.1%	324	782	70.7%	688	73	9.6%	302	731	70.7%

Table 12-50 shows that on average, 68.8 percent of late outage requests which were not modeled in the Monthly Balance of Planning Period FTR Auction, submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates, were approved and complete in the 2017/2018 planning period, compared to 69.5 percent in the 2016/2017 planning period.

Table 12-50 Late transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction and submitted after monthly bidding opening date: planning periods 2016/2017 and 2017/2018

	2016/2017			2017/2018		
	Completed Outages	Total	Percent	Completed Outages	Total	Percent
Jun	639	895	71.4%	627	852	73.6%
Jul	476	698	68.2%	410	608	67.4%
Aug	523	733	71.4%	473	651	72.7%
Sep	495	772	64.1%	406	599	67.8%
Oct	644	901	71.5%	595	867	68.6%
Nov	536	832	64.4%	490	791	61.9%
Dec	534	723	73.9%	508	693	73.3%
Jan	401	592	67.7%	493	745	66.2%
Feb	447	674	66.3%	457	699	65.4%
Mar	580	806	72.0%	569	800	71.1%
Apr	575	789	72.9%			
May	668	966	69.2%			
Avg	543	782	69.5%	503	731	68.8%

Transmission Facility Outage Analysis in the Day-Ahead Energy 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 so that market participants can understand market conditions and so that PJM can accurately model market conditions in the day-ahead market. PJM requires transmission owners to submit changes to outages scheduled for the next two days no later than 09:30 am. [50]

In order to analyze the market impact, the outage requests that affect the operating day are compared: before the day-ahead market is closed; when the day-ahead market save cases are created; and during the operating day. The list of approved or active outage requests before the day-ahead market is closed is the view of outages available to market participants. The day-ahead market model uses a list of outages as an input. The list of outages that actually occurred during the operating day are the outages that affect the real-time market. If the three sets of outages are the same, there is no potential impact on markets. If the three sets of outages differ, there is a potential impact on markets.

For example for the operating day of November 23, 2016, Figure 12-3 shows that: there were 421 approved or active outages seen by market participants before the day-ahead market was closed; there were 282 outage requests included in the day-ahead market model; there were 273 outage request included in both sets of outage; there were 148 outage requests approved or active before the day-ahead market was closed but not included as inputs in day-ahead market model; and there were nine outage requests included in day-ahead market model but not available to market participants prior to the day-ahead market.

Figure 12-3 Illustration of day-ahead market analysis: November 22, 2016

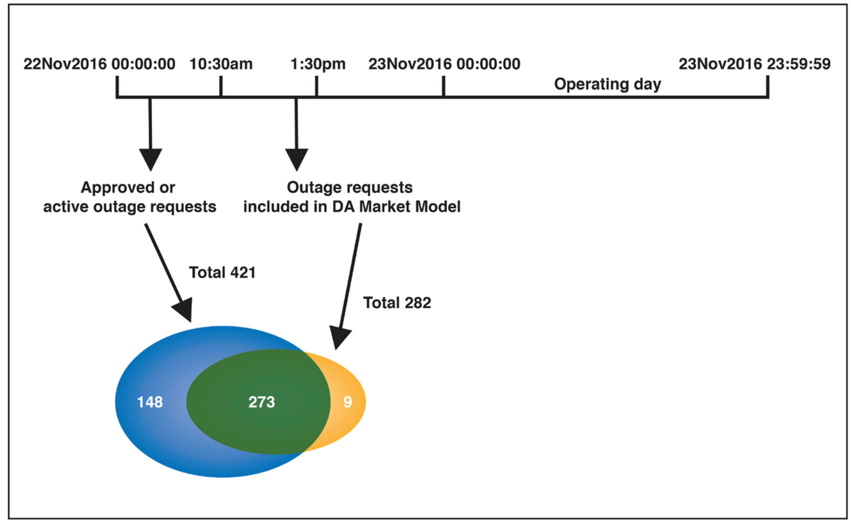


Figure 12-4 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.

50 PJM. "Manual 3: Transmission Operations," Rev. 52 (Dec. 22, 2017) at 74

Figure 12-4 Approved or active outage requests: January 2015 through March 2018

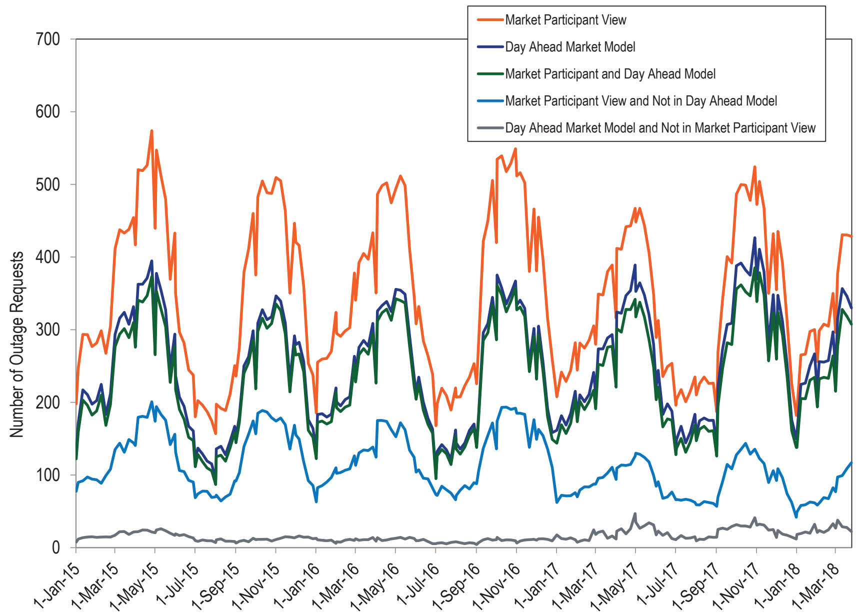


Figure 12-5 compares the weekly average number of outages included as inputs to the day-ahead market by PJM with the outages that actually occurred during the operating day.

Figure 12-5 Day-ahead market model outages: January 2015 through March 2018

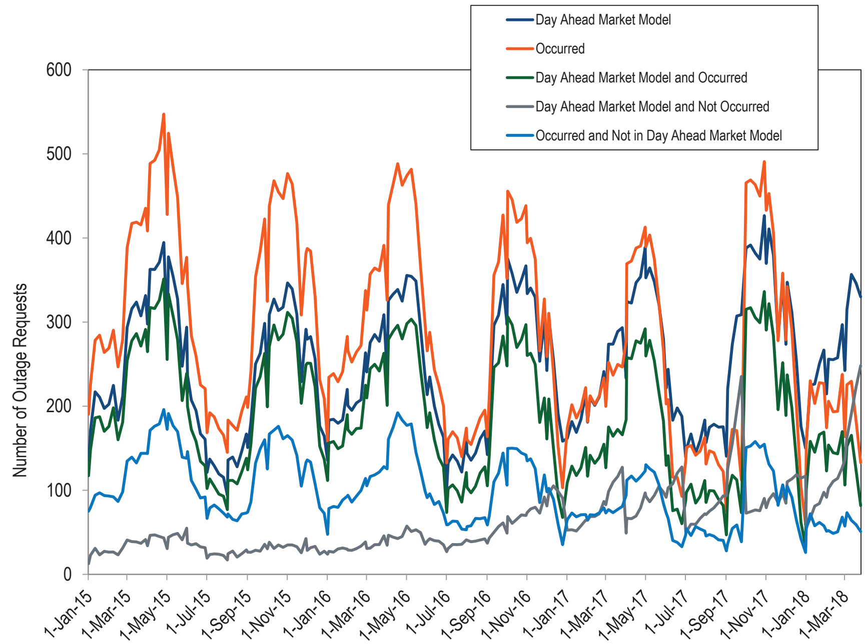


Figure 12-6 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

Figure 12-6 Approved or active outage requests: January 2015 through March 2018

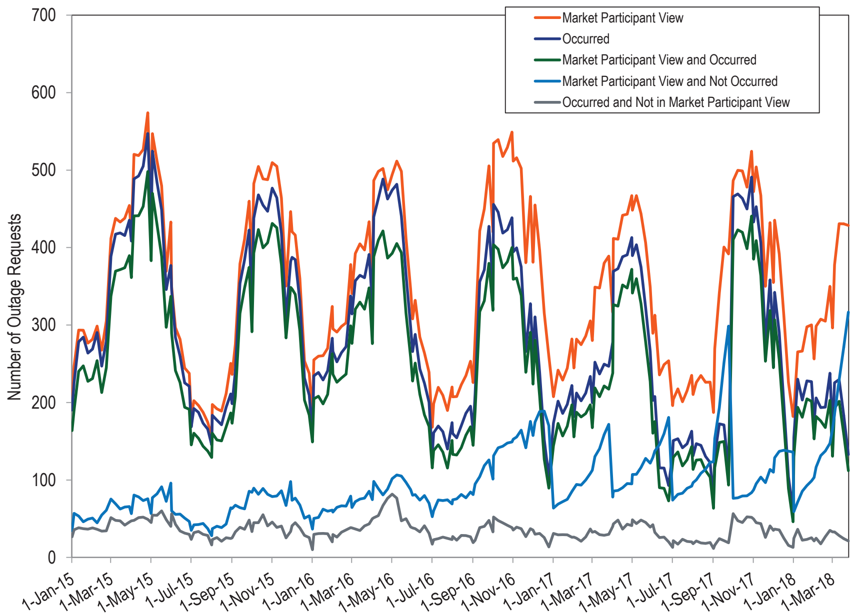


Figure 12-4, Figure 12-5, and Figure 12-6 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or approved outages available to day-ahead market participants are more consistent with the outages that actually occurred in real time than with the outages included in the day-ahead market model.