Generation and Transmission Planning[1]

Overview

Generation Interconnection Planning

Existing Generation Mix

- As of September 30, 2018, PJM had an installed capacity of 195,488.2 MW, of which 57,891.9 MW (29.6 percent) are coal fired steam units, 43,063.1 MW (22.0 percent) are combined cycle units and 34,257.6 MW (17.5 percent) are nuclear units. This measure of installed capacity 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.
- The largest zone by total installed capacity is AEP. Of the 195,488.2 MW of PJM installed capacity, 31,343.0 MW (16.0 percent) are in the AEP Zone, of which 14,727.8 MW (47.0 percent) are coal fired steam units, 6,990.0 MW (22.3 percent) are combined cycle units and 2,071.0 MW (6.6 percent) are nuclear units.
- The largest state by total installed capacity is Pennsylvania. Of the 195,488.2 MW of installed capacity, 43,207.6 MW (22.1 percent) are in Pennsylvania, of which 12,112.5 MW (28.0 percent) are combined cycle units, 9,648.8 MW (22.3 percent) are nuclear units and 9,467.7 MW (21.9 percent) are coal fired steam units.
- Of the 195,488.2 MW of installed capacity, 76,587.5 MW (39.2 percent) are from units older than 40 years, of which 41,426.7 MW (54.1 percent) are coal fired steam units and 16,044.9 MW (20.9 percent) are nuclear units.

Generation Retirements[2]

- There are 43,125.6 MW of generation that have been, or are planned to be, retired between 2011 and 2021, of which 30,821.4 MW (71.5 percent) are coal fired steam units. Coal unit retirements are primarily a result of the inability of coal units to compete with efficient combined cycle units burning low cost gas.
- In the first nine months of 2018, 4,894.2 MW of generation retired. The largest generator that retired in first nine months of 2018 was the joint owned 600 MW Killen 2 unit (402 MW owned by AES Corporation and 198 MW owned by Vistra Energy Corporation) located in the Dayton Power and Light (DAY) Zone. Of the 4,894.2 MW of generation that retired, 2,364.0 MW (48.3 percent) were located in the DAY Zone.
- There are 12,468.0 MW of generation that have requested retirement after September 30, 2018, of which 6,791.0 MW (54.5 percent) are located in the ATSI Zone, 7,341.8 MW (58.9 percent) are coal fired steam units and 4,716.0 MW (37.8 percent) are nuclear units. The largest generator pending retirement is the 1,240 MW Perry U1 Nuclear Generating Unit located in the ATSI Zone.

Generation Queue[3]

- The total MW in queues increased by 22,169.1 MW (28.0 percent) from 79,224.3 MW at the end of 2017 to 101,393.4 MW on September 30, 2018.
- 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 September 30, 2018, there were 50,201.7 MW of natural gas fired capacity active, suspended or under construction in PJM queues (including combined cycle units, CTs, RICE units, and natural gas fired steam units). As of September 30, 2018, there were only 147.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.
- As of September 30, 2018, 3,969 projects, representing 504,007.2 MW, have entered the queue process since its inception in 1998. Of those, 805 projects, representing 59,737.9 MW, went into service. Of the projects that entered the queue process, 2,323 projects, representing 342,875.9 MW (68.0 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by

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>.

taking up queue positions, increasing interconnection costs and creating uncertainty.

Regional Transmission Expansion Plan (RTEP)

Backbone Facilities

- 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.[4]

Market Efficiency Process

- Through September 30, 2018, PJM has completed two market efficiency cycles. In the first cycle, PJM received 93 proposals for 57 identified issues. In the second market efficiency cycle, PJM received 96 proposals for four identified issues. The proposal window for 2018/2019 will open on November 1, 2018, and will close on Februray 28, 2019.
- Approved market efficiency projects periodically undergo a reevaluation process to ensure that the benefit/cost ratio continues to meet the 1.25:1 threshold. The Transource AP-South project was reevaluated in September 2017, February 2018 and again in September 2018. The project exceeded the 1.25:1 threshold in all reevaluations.

PJM MISO Interregional Targeted Market Efficiency Process (TMEP)

- The first Targeted Market Efficiency Process (TMEP) analysis occurred in 2017 and 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.[5]
- The 2018 TMEP analysis included the investigation of congestion on 61 market to market flowgates. The study resulted in the evaluation of 19 potential upgrades, resulting in the recommendation of two TMEP projects. The two projects address $25 million in historical congestion, with a TMEP benefit of $31.9 million. The projects have a total cost of $4.5 million, with a 7.1 average benefit/cost ratio. PJM and MISO will present the two recommended projects to their boards for approval in December, 2018.[6]

Supplemental Transmission Projects

- The average number of supplemental projects in each expected in service year increased by 500.0 percent, from 20 for years 1998 through 2007 (pre Order 890) to 120 for years 2008 through 2018 (post Order 890).

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that has, or is approaching, the end of its useful life. End of life transmission projects fall under the Transmission Owner Form 715 Planning Criteria, and are currently exempt from the competitive planning process.[7] End of life transmission projects are already included in the supplemental projects totals or, if included in the transmission owners' reliability plan, will be included in the baseline project list as a reliability criteria project.

Board Authorized 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

4 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>.

5 See PJM. "*MISO PJM IPSAC*," (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.

6 See PJM. "*MISO PJM IPSAC*," (October 5, 2018) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20181005/20181005-ipsac-presentation.ashx>.

7 See PJM Operating Agreement. Schedule 6 § 1.5.8(o).

Board of Managers for authorization. In the first nine months of 2018, the PJM Board approved $1.60 billion in upgrades.

Transmission Competition

- The MMU makes several recommendations related to the competitive transmission planning process. The recommendations include improved process transparency, incorporation of competition between transmission and generation alternatives and the removal of barriers to competition from merchant transmission. These recommendations will ensure that the process is an open and transparent process that results in the most cost effective solutions.
- On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM to develop a comparative framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. The initial motion required the comparative framework to be presented at the December 2018 meeting of the MRC for vote and to be effective for the 2018 long lead project proposal window. At the August 23, 2018, meeting of the MRC, the committee approved a motion to delay the comparative framework deadlines by one year.

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 were12,123 transmission outage requests submitted in the 2018/2019 planning period. Of the requested outages, 70.5 percent of the requested outages were planned for less than or equal to five days and 10.2 percent of requested outages were planned for greater than 30 days. Of the requested outages, 37.9 percent were late according to the rules in PJM's Manual 3.

Recommendations

The MMU recommends improvements to the planning process:

Generation Retirements

- 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.)

Generation Queue

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends 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 continuing 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.)

8 PJM. "Manual 03: Transmission Operations," Rev. 53 (June 1, 2018) Section 4.

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>.

- 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.)

Market Efficiency Process

- The MMU recommends that PJM reevaluate the rules governing cost benefit analysis and cost allocation for economic projects. (Priority: Medium. New recommendation. Status: Not adopted.)

Supplemental Transmission Projects

- The MMU recommends, to ensure maximum competition, that PJM support ending the exemption of supplemental projects from the Order No. 1000 competitive process and to review the basis for all such exemptions. (Priority: Medium. First reported 2017. Status: Not adopted.)

Transmission Competition

- 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 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 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 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.)

Transmission Facility Outages

- 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.)

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. The ability of transmission owners to block competition for supplemental projects and end of life projects and any policy reasons for that policy should be reevaluated. 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.

Generation Interconnection Planning

Existing Generation Mix

Table 12-1 shows the existing PJM capacity by control zone and unit type.[10] As of September 30, 2018, PJM had an installed capacity of 195,488.2 MW, of which 57,891.9 MW (29.6 percent) are coal fired steam units, 43,063.1 MW (22.0 percent) are combined cycle units and 34,257.6 MW (17.5 percent) are nuclear units. This measure of installed capacity 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.

The largest zone by total installed capacity is AEP. Of the 195,488.2 MW of PJM installed capacity, 31,343.0 MW (16.0 percent) are in the AEP Zone, of which 14,727.8 MW (47.0 percent) are coal fired steam units, 6,990.0 MW (22.3 percent) are combined cycle units and 2,071.0 MW (6.6 percent) are nuclear units.

Table 12-1 Existing PJM capacity: September 30, 2018 (By zone and unit type (MW))[11]

Zone	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
AECO	0.0	901.9	544.7	0.0	26.0	1.6	0.0	0.0	0.0	0.0	4.0	10.6	59.4	613.9	0.0	0.0	0.0	7.5	2,169.5
AEP	6.0	6,990.0	3,661.2	0.0	21.0	0.0	66.0	486.9	2,071.0	0.0	0.0	20.4	14.7	14,727.8	738.0	0.0	50.0	2,490.0	31,343.0
APS	78.9	1,129.0	1,223.3	0.0	2.0	0.0	0.0	129.2	0.0	0.0	29.6	18.3	55.1	5,409.0	0.0	0.0	0.0	1,191.5	9,265.9
ATSI	0.0	2,150.5	958.0	0.0	659.4	0.0	0.0	0.0	2,134.0	0.0	18.5	46.1	0.0	5,394.0	325.0	0.0	0.0	0.0	11,685.5
BGE	0.0	0.0	500.1	0.0	267.8	0.0	0.0	0.4	1,716.0	0.0	0.0	7.2	1.1	1,713.0	240.5	397.0	57.0	0.0	4,900.1
ComEd	128.5	2,621.1	6,969.3	0.0	226.2	0.0	0.0	0.0	10,473.5	0.0	0.0	38.3	9.0	4,124.1	1,326.0	0.0	0.0	3,187.9	29,103.9
DAY	0.0	0.0	1,344.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	4.5	1.1	0.0	0.0	0.0	0.0	0.0	1,384.1
DEOK	20.0	522.2	598.0	0.0	56.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	0.0	1,857.0	47.0	0.0	0.0	0.0	3,217.0
DLCO	0.0	244.0	0.0	0.0	15.0	0.0	0.0	6.3	1,777.0	0.0	0.0	0.0	0.0	565.0	0.0	0.0	0.0	0.0	2,607.3
Dominion	0.0	7,499.6	3,835.3	0.0	266.4	0.0	3,003.0	586.3	3,581.3	0.0	39.0	112.8	512.4	4,705.6	351.0	1,586.0	368.4	208.0	26,655.1
DPL	0.0	1,742.5	1,298.2	0.0	478.2	30.0	0.0	0.0	0.0	0.0	88.0	14.1	213.4	410.0	882.0	153.0	0.0	0.0	5,309.4
EKPC	0.0	0.0	774.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	0.0	1,687.0	0.0	0.0	0.0	0.0	2,531.0
JCPL	0.0	2,402.5	531.1	0.0	232.0	0.4	400.0	0.0	0.0	0.0	0.0	16.1	279.0	0.0	0.0	0.0	10.0	0.0	3,871.1
Met-Ed	0.0	1,616.0	2.0	0.0	398.5	0.0	0.0	19.0	805.0	0.0	0.0	33.4	0.0	115.0	0.0	0.0	60.0	0.0	3,048.9
PECO	0.0	3,209.0	50.8	0.0	834.0	0.0	1,070.0	572.0	4,546.8	0.0	2.0	0.9	3.0	3.3	762.0	0.0	163.0	0.0	11,216.8
PENELEC	28.4	850.0	350.5	0.0	57.0	0.0	513.0	77.8	0.0	0.0	106.8	17.8	0.0	6,141.5	610.0	0.0	42.0	1,028.8	9,823.6
Pepco	0.0	1,710.0	764.2	0.0	308.0	0.0	0.0	0.0	0.0	0.0	0.0	11.1	0.0	2,433.0	1,164.1	0.0	52.0	0.0	6,442.4
PPL	20.0	5,064.5	252.0	0.0	150.1	0.0	0.0	706.6	2,520.0	0.0	17.0	24.7	15.0	2,642.9	2,449.0	10.0	29.0	216.5	14,117.3
PSEG	5.7	4,410.3	1,039.2	0.0	0.0	0.0	0.0	5.0	3,493.0	0.0	0.0	6.0	195.6	0.0	3.0	0.0	188.1	0.0	9,345.8
XIC	0.0	0.0	691.6	0.0	0.0	0.0	0.0	269.1	1,140.0	0.0	0.0	0.0	0.0	5,349.8	0.0	0.0	0.0	0.0	7,450.5
Total	287.5	43,063.1	25,388.0	0.0	3,997.6	32.0	5,052.0	3,040.6	34,257.6	0.0	338.9	387.0	1,358.8	57,891.9	8,897.6	2,146.0	1,019.5	8,330.2	195,488.2

10 The unit type RICE refers to Reciprocating Internal Combustion Engines.

11 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 12-2 shows the installed capacity by state for each fuel type. The largest state by total installed capacity is Pennsylvania. Of the 195,488.2 MW of installed capacity, 43,207.6 MW (22.1 percent) are in Pennsylvania, of which 12,112.5 MW (28.0 percent) are combined cycle units, 9,648.8 MW (22.3 percent) are nuclear units and 9,467.7 MW (21.9 percent) are coal fired steam units.

Table 12-2 Existing PJM capacity: September 30, 2018 (By state and unit type (MW))

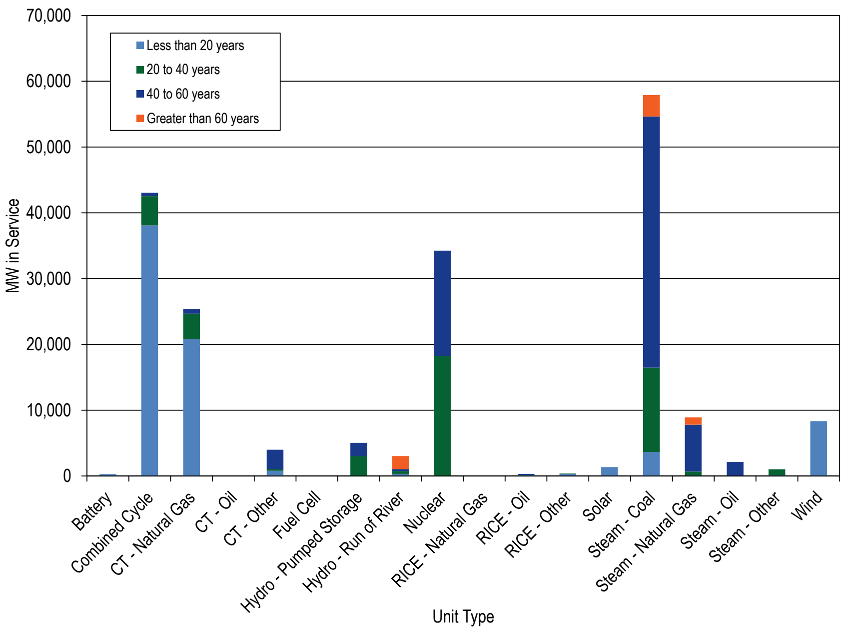
State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
DE	0.0	742.5	325.5	0.0	116.3	30.0	0.0	0.0	0.0	0.0	0.0	8.1	0.0	410.0	882.0	0.0	0.0	0.0	2,514.4
IL	128.5	2,621.1	6,969.3	0.0	226.2	0.0	0.0	0.0	10,473.5	0.0	0.0	38.3	9.0	4,124.1	1,326.0	0.0	0.0	3,187.9	29,103.9
IN	0.0	1,835.0	441.4	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	3.2	10.1	2,620.0	0.0	0.0	0.0	1,823.2	6,741.1
KY	0.0	0.0	1,618.1	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	0.0	1,687.0	278.0	0.0	0.0	0.0	3,719.1
MD	20.0	2,710.0	2,237.0	0.0	591.7	0.0	0.0	0.4	1,716.0	0.0	76.0	24.3	239.6	4,386.0	1,404.6	550.0	109.0	295.0	14,359.6
MI	0.0	1,200.0	0.0	0.0	4.8	0.0	0.0	11.8	2,071.0	0.0	0.0	3.2	4.6	0.0	0.0	0.0	0.0	0.0	3,295.4
NC	0.0	165.0	0.0	0.0	0.0	0.0	0.0	315.0	0.0	0.0	18.0	0.0	277.8	115.5	0.0	0.0	0.0	208.0	1,099.3
NJ	5.7	7,714.7	2,115.0	0.0	258.0	2.0	400.0	5.0	3,493.0	0.0	4.0	32.7	533.9	613.9	3.0	0.0	198.1	7.5	15,386.5
OH	24.0	6,627.7	4,201.2	0.0	731.6	0.0	0.0	200.0	2,134.0	0.0	52.5	55.4	1.1	12,998.8	372.0	0.0	0.0	666.8	28,065.1
PA	48.4	12,112.5	1,542.7	0.0	1,454.6	0.0	1,583.0	1,445.7	9,648.8	0.0	155.4	95.1	18.0	9,467.7	3,821.0	10.0	294.0	1,510.7	43,207.6
TN	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	50.0	0.0	50.0
VA	0.0	7,334.6	4,172.3	0.0	603.4	0.0	3,069.0	460.1	3,581.3	0.0	33.0	118.8	264.6	3,585.1	811.0	1,586.0	368.4	0.0	25,987.6
WV	60.9	0.0	1,073.9	0.0	11.0	0.0	0.0	189.3	0.0	0.0	0.0	8.0	0.0	12,534.0	0.0	0.0	0.0	631.1	14,508.2
XIC	0.0	0.0	691.6	0.0	0.0	0.0	0.0	269.1	1,140.0	0.0	0.0	0.0	0.0	5,349.8	0.0	0.0	0.0	0.0	7,450.5
Total	287.5	43,063.1	25,388.0	0.0	3,997.6	32.0	5,052.0	3,040.6	34,257.6	0.0	338.9	387.0	1,358.8	57,891.9	8,897.6	2,146.0	1,019.5	8,330.2	195,488.2

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of September 30, 2018. Of the 195,488.2 MW of installed capacity, 76,587.5 MW (39.2 percent) are from units older than 40 years, of which 41,426.7 MW (54.1 percent) are coal fired steam units and 16,044.9 MW (20.9 percent) are nuclear units.

Table 12-3 PJM capacity (MW) by unit type and age (years): September 30, 2018

Age (years)	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
Less than 20	287.5	38,087.6	20,845.2	0.0	799.0	32.0	0.0	339.2	0.0	0.0	128.4	341.6	1,358.8	3,655.0	82.0	0.0	97.4	8,330.2	74,383.8
20 to 40	0.0	4,443.5	3,840.6	0.0	217.2	0.0	3,003.0	385.2	18,212.7	0.0	37.0	45.4	0.0	12,810.2	600.0	0.0	922.1	0.0	44,516.9
40 to 60	0.0	532.0	702.2	0.0	2,981.4	0.0	2,049.0	340.0	16,044.9	0.0	173.5	0.0	0.0	38,191.4	7,131.1	2,146.0	0.0	0.0	70,291.5
Greater than 60	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,976.2	0.0	0.0	0.0	0.0	0.0	3,235.3	1,084.5	0.0	0.0	0.0	6,296.0
Total	287.5	43,063.1	25,388.0	0.0	3,997.6	32.0	5,052.0	3,040.6	34,257.6	0.0	338.9	387.0	1,358.8	57,891.9	8,897.6	2,146.0	1,019.5	8,330.2	195,488.2

Figure 12-1 PJM capacity (MW) by age (years): September 30, 2018



Generation Retirements[12]

Generating units generally plan to retire when they are not economic and do not expect to be economic. The MMU performs an analysis of the economics of all units that plan to retire in order to verify that the units are not economic and there is no potential exercise of market power through physical withholding that could advantage the owner's portfolio. The definition of economic is that unit net revenues are greater than or equal to the unit's avoidable or going forward costs.

PJM does not have the authority to order generating plants to continue operating. PJM's responsibility is to ensure system reliability. When a unit retirement creates reliability issues based on existing and planned generation facilities and on existing and planned transmission facilities, PJM identifies transmission solutions.[13]

Rules that preserve the Capacity Injection Rights (CIRs) associated with retired units impose significant costs on new entrants. Currently, CIRs persist for one year if unused, and they can be further extended, at no cost, if assigned to a new project in the interconnection queue at the same point of interconnection.[14] Reforms that require the holders of CIRs to use or lose them, and/or impose costs to holding or transferring them, could make new entry appropriately more attractive. The economic and policy rationale for extending CIRs for inactive units is not clear. Incumbent providers receive a significant advantage simply by imposing on new entrants the entire cost of system upgrades needed to accommodate new entrants. The policy question of whether CIRs should persist after the retirement of a unit should be addressed. Even if the policy treatment of such CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.

In May 2012, PJM stakeholders (through the Interconnection Process Senior Task Force (IPSTF)) modified the rules to reduce the length of time for which CIRs are retained by the current owner after unit retirements from three years to one.[15] The MMU recognized the progress made in this rule change, but does not believe it fully addressed the issues. 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.[16]

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

13 See PJM. "Explaining Power Plant Retirements in PJM," at <http://learn.pjm.com/three-priorities/planning-for-the-future/explaining-power-plant-retirements.aspx>.

14 See PJM OATT § 230.3.3.

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

16 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>.

Generation Retirements 2011 through 2021

Table 12-4 shows that there are 43,125.6 MW of generation that have been, or are planned to be, retired between 2011 and 2021, of which 30,821.4 MW (71.5 percent) are coal fired steam units. Coal unit retirements are primarily a result of the inability of coal units to compete with efficient combined cycle units burning low cost gas.

Table 12-4 Summary of PJM unit retirements by unit type (MW): 2011 through 2021

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
Retirements 2011	0.0	0.0	0.0	0.0	128.3	0.0	0.0	0.0	0.0	0.0	2.7	0.0	0.0	543.0	522.5	0.0	0.0	0.0	1,196.5
Retirements 2012	0.0	0.0	250.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,907.9	0.0	548.0	16.0	0.0	6,961.9
Retirements 2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	7.0	0.0	2,589.9	82.0	166.0	8.0	0.0	2,858.8
Retirements 2014	0.0	0.0	136.0	0.0	422.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	0.0	2,239.0	158.0	0.0	0.0	0.0	2,970.3
Retirements 2015	0.0	0.0	1,319.0	0.0	858.2	0.0	0.0	0.0	0.0	0.0	10.3	0.0	0.0	7,064.8	0.0	0.0	0.0	10.4	9,262.7
Retirements 2016	0.0	0.0	0.0	0.0	71.0	0.0	0.5	0.0	0.0	0.0	8.0	3.9	0.0	243.0	74.0	0.0	0.0	0.0	400.4
Retirements 2017	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	2,038.0	34.0	0.0	0.0	0.0	2,112.8
Retirements 2018	1.0	425.0	0.0	0.0	39.6	0.0	0.0	0.0	614.5	0.0	17.2	6.9	0.0	2,854.0	680.0	148.0	108.0	0.0	4,894.2
Planned Retirements (November 2018 and later)	0.0	0.0	50.8	0.0	30.4	0.0	0.0	0.0	4,716.0	0.0	13.0	0.0	0.0	7,341.8	316.0	0.0	0.0	0.0	12,468.0
Total	41.0	425.0	1,755.8	0.0	1,789.5	0.0	0.5	0.0	5,330.5	0.0	57.1	33.9	0.0	30,821.4	1,866.5	862.0	132.0	10.4	43,125.6

Table 12-5 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2021, while Table 12-6 shows these retirements by state. Of the 43,125.6 MW of units that has been, or are planned to be, retired between 2011 and 2021, 30,821.4 MW (71.5 percent) are coal fired steam units. These coal fired steam units have an average age of 53.0 years and an average size of 192.6 MW. Over half of the retiring coal fired steam units, 57.8 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 12-5 Retirements by unit type: 2011 through 2021

Unit Type	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Battery	2	20.5	7.0	41.0	0.1%
Combined Cycle	2	212.5	25.5	425.0	1.0%
Combustion Turbine	92	38.8	42.7	3,545.3	8.2%
Natural Gas	42	41.8	43.7	1,755.8	4.1%
Oil	0	0.0	0.0	0.0	0.0%
Other	50	35.8	41.6	1,789.5	4.1%
Fuel Cell	0	0.0	0.0	0.0	0.0%
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%
Nuclear	6	888.4	41.6	5,330.5	12.4%
RICE	21	4.3	28.4	91.0	0.2%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	11	5.2	46.1	57.1	0.1%
Other	10	3.4	10.6	33.9	0.1%
Solar	0	0.0	0.0	0.0	0.0%
Steam	184	139.5	44.9	33,681.9	78.1%
Coal	160	192.6	53.0	30,821.4	71.5%
Natural Gas	16	116.7	61.3	1,866.5	4.3%
Oil	4	215.5	45.5	862.0	2.0%
Other	4	33.0	19.8	132.0	0.3%
Wind	1	10.4	15.6	10.4	0.0%
Total	309	139.6	47.5	43,125.6	100.0%

Table 12-6 Retirements (MW) by unit type and state: 2011 through 2021

State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
DC	0.0	0.0	0.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	548.0	0.0	0.0	788.0
DE	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	254.0	34.0	0.0	0.0	0.0	288.0
IL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.5	0.0	1,624.0	0.0	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	0.0	0.0	0.0	0.0	982.0	0.0	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	0.0	0.0	0.0	0.0	995.0	0.0	0.0	0.0	0.0	995.0
MD	0.0	0.0	115.0	0.0	66.6	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	635.0	74.0	0.0	0.0	0.0	891.4
NC	0.0	0.0	0.0	0.0	31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.5	0.0	0.0	0.0	0.0	355.5
NJ	0.0	158.0	1,590.0	0.0	1,046.6	0.0	0.5	0.0	614.5	0.0	8.0	9.8	0.0	1,543.0	932.5	148.0	0.0	0.0	6,050.9
OH	40.0	0.0	0.0	0.0	286.0	0.0	0.0	0.0	2,134.0	0.0	32.3	0.9	0.0	13,092.6	0.0	0.0	0.0	0.0	15,585.8
PA	1.0	0.0	50.8	0.0	52.0	0.0	0.0	0.0	2,582.0	0.0	13.9	8.0	0.0	4,713.3	283.0	166.0	49.0	10.4	7,929.4
VA	0.0	267.0	0.0	0.0	67.3	0.0	0.0	0.0	0.0	0.0	2.9	2.0	0.0	2,739.0	543.0	0.0	83.0	0.0	3,704.2
WV	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	3,919.0	0.0	0.0	0.0	0.0	3,919.0
Total	41.0	425.0	1,755.8	0.0	1,789.5	0.0	0.5	0.0	5,330.5	0.0	57.1	33.9	0.0	30,821.4	1,866.5	862.0	132.0	10.4	43,125.6

A map of unit retirements between 2011 and 2021 is shown in Figure 12-2 with a mapping to unit names identified in Table 12-7.

Figure 12-2 Map of PJM unit retirements: 2011 through 2021

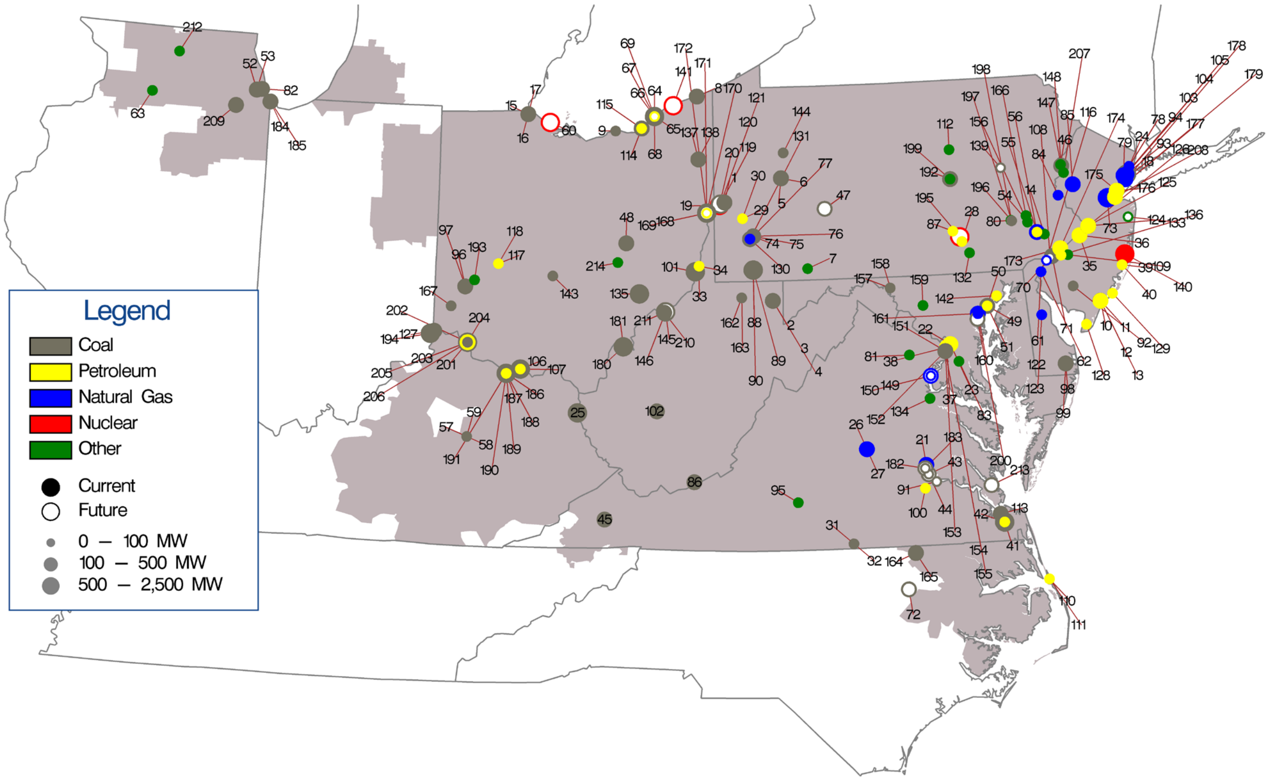


Table 12-7 Unit identification for map of PJM unit retirements: 2011 through 2021

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AES Beaver Valley	36	Burlington 9	71	Eddystone 2	106	Killen 2	141	Perry U1 Nuclear Generating Unit	176	Sewaren 2	211	Willow Island 2
2	Albright 1	37	Buzzard Point East Banks 1,2,4-8	72	Edgecomb NUG (Rocky 1-2)	107	Killen CT	142	Perryman 2	177	Sewaren 3	212	Winnebago Landfill
3	Albright 2	38	Buzzard Point West Banks 1-9	73	Edison 1-3	108	Kimberly Clark Generator	143	Picway 5	178	Sewaren 4	213	Yorktown 1-2
4	Albright 3	39	Cedar 1	74	Elrama 1	109	Kinsley Landfill	144	Piney Creek NUG	179	Sewaren 6	214	Zanesville Landfill
5	Armstrong 1	40	Cedar 2	75	Elrama 2	110	Kitty Hawk GT 1	145	Pleasants Power Station U1	180	Sporn 1-4		
6	Armstrong 2	41	Chesapeake 1-4	76	Elrama 3	111	Kitty Hawk GT 2	146	Pleasants Power Station U2	181	Sporn 5		
7	Arnold (Green Mtn. Wind Farm	42	Chesapeake 7-10	77	Elrama 4	112	Koppers Co. IPP	147	Portland 1	182	Spruance NUG1 (Rich 1-2)		
8	Ashtabula 5	43	Chesterfield 3	78	Essex 10-11	113	Lake Kingman	148	Portland 2	183	Spruance NUG2 (Rich 3-4)		
9	Avon Lake 7	44	Chesterfield 4	79	Essex 12	114	Lake Shore 18	149	Possum Point 3	184	State Line 3		
10	BL England 1	45	Clinch River 3	80	Evergreen Power United Corstack	115	Lake Shore EMD	150	Possum Point 4	185	State Line 4		
11	BL England 2	46	Columbia Dam Hydro	81	Fauquier County Landfill	116	MH50 Markus Hook Co-gen	151	Potomac River 1	186	Stuart 1		
12	BL England 3	47	Colver Power Project	82	Fisk Street 19	117	Mad River CTs A	152	Potomac River 2	187	Stuart 2		
13	BL England Diesel Units 1-4	48	Conesville 3	83	GUDE Landfill	118	Mad River CTs B	153	Potomac River 3	188	Stuart 3		
14	Barbados AES Battery	49	Crane 1	84	Gilbert 1-4	119	Mansfield 1	154	Potomac River 4	189	Stuart 4		
15	Bay Shore 2	50	Crane 2	85	Glen Gardner 1-8	120	Mansfield 2	155	Potomac River 5	190	Stuart Diesels 1-4		
16	Bay Shore 3	51	Crane GT1	86	Glen Lyn 5-6	121	Mansfield 3	156	Pottstown LF (Moser)	191	Stuart Diesels 1-4		
17	Bay Shore 4	52	Crawford 7	87	Harrisburg 4 CT	122	McKee 1	157	R Paul Smith 3	192	Sunbury 1-4		
18	Bayonne Cogen Plant (CC)	53	Crawford 8	88	Hatfield's Ferry 1	123	McKee 2	158	R Paul Smith 4	193	Tait Battery		
19	Beaver Valley U1 Nuclear Generating Unit	54	Cromby 1	89	Hatfield's Ferry 2	124	Mercer 1	159	Reichs Ford Road Landfill Generator	194	Tanners Creek 1-4		
20	Beaver Valley U2 Nuclear Generating Unit	55	Cromby 2	90	Hatfield's Ferry 3	125	Mercer 2	160	Riverside 4	195	Three Mile Island Unit 1		
21	Bellemeade	56	Cromby D	91	Hopewell James River Cogeneration	126	Mercer 3	161	Riverside 6	196	Titus 1		
22	Benning 15	57	Dale 1-2	92	Howard Down 10	127	Miami Fort 6	162	Riversville 5	197	Titus 2		
23	Benning 16	58	Dale 3	93	Hudson 1	128	Middle 1-3	163	Riversville 6	198	Titus 3		
24	Bergen 3	59	Dale 4	94	Hudson 2	129	Missouri Ave B,C,D	164	Roanoke Valley 1	199	Viking Energy NUG		
25	Big Sandy 2	60	Davis Besse U1 Nuclear Generating Unit	95	Hurt NUG	130	Mitchell 2	165	Roanoke Valley 2	200	Wagner 2		
26	Bremo 3	61	Deepwater 1	96	Hutchings 1-3, 5-6	131	Mitchell 3	166	Rolling Hills Landfill Generator	201	Walter C Beckjord 1		
27	Bremo 4	62	Deepwater 6	97	Hutchings 4	132	Modern Power Landfill NUG	167	SMART Paper	202	Walter C Beckjord 2		
28	Brunner Island Diesels	63	Dixon Lee Landfill Generator	98	Indian River 1	133	Monmouth NUG landfill	168	Sammis 1-4	203	Walter C Beckjord 3		
29	Brunot Island 1B	64	Eastlake 1	99	Indian River 3	134	Morris Landfill Generator	169	Sammis 5	204	Walter C Beckjord 4		
30	Brunot Island 1C	65	Eastlake 2	100	Ingenco Petersburg	135	Muskingum River 1-5	170	Sammis 6	205	Walter C Beckjord 5-6		
31	Buggs Island 1 (Mecklenberg)	66	Eastlake 3	101	Kammer 1-3	136	National Park 1	171	Sammis 7	206	Walter C Beckjord GT 1-4		
32	Buggs Island 2 (Mecklenberg)	67	Eastlake 4	102	Kanawha River 1-2	137	Niles 1	172	Sammis Diesel	207	Warren County Landfill		
33	Burger 3	68	Eastlake 5	103	Kearny 10	138	Niles 2	173	Schuylkill 1	208	Werner 1-4		
34	Burger EMD	69	Eastlake 6	104	Kearny 11	139	Northeastern Power NEPCO	174	Schuylkill Diesel	209	Will County 3		
35	Burlington 8,11	70	Eddystone 1	105	Kearny 9	140	Oyster Creek	175	Sewaren 1	210	Willow Island 1		

Current Year Generation Retirements

Table 12-8 shows that in the first nine months of 2018, 4,894.2 MW of generation retired. The largest generator that retired in first nine months of 2018 was the joint owned 600 MW Killen 2 unit (402 MW owned by AES Corporation and 198 MW owned by Vistra Energy Corporation) located in the Dayton Power and Light (DAY) Zone. Of the 4,894.2 MW of generation that retired, 2,364.0 MW (48.3 percent) were located in the DAY Zone.

Table 12-8 Unit deactivations: January through September, 2018[17]

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Age (Years)	Retirement Date
Biogas Energy Solutions, LLC	Dixon Lee Landfill Generator	4.0	RICE-Other	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	RICE-Oil	PPL	50.8	25-Feb-18
Dominion Resources, Inc.	Buggs Island 1 (Mecklenberg)	69.0	Steam-Coal	Dominion	25.5	09-Apr-18
Dominion Resources, Inc.	Buggs Island 2 (Mecklenberg)	69.0	Steam-Coal	Dominion	25.5	09-Apr-18
Dominion Resources, Inc.	Bellemeade	267.0	Combined Cycle	Dominion	21.2	16-Apr-18
Dominion Resources, Inc.	Bremo 3	71.0	Steam-Natural Gas	Dominion	67.9	16-Apr-18
Dominion Resources, Inc.	Bremo 4	156.0	Steam-Natural Gas	Dominion	59.7	16-Apr-18
Evergreen Community Power LLC	Evergreen Power United Corstack	25.0	Steam-Biomass	Met-Ed	8.7	01-May-18
Biogas Energy Solutions, LLC	Morris Landfill Generator	2.1	RICE-Other	ComEd	5.0	31-May-18
South Jersey Industries, Inc.	Reichs Ford Road Landfill Generator	1.6	CT-Other	APS	8.1	31-May-18
American Electric Power Company, Inc.	Stuart 2	150.0	Steam-Coal	DAY	47.7	01-Jun-18
American Electric Power Company, Inc.	Stuart 3	150.0	Steam-Coal	DAY	46.1	01-Jun-18
American Electric Power Company, Inc.	Stuart 4	150.0	Steam-Coal	DAY	44.0	01-Jun-18
American Electric Power Company, Inc.	Stuart Diesels 1-4	2.4	RICE-Oil	DAY	48.7	01-Jun-18
Avenue Capital Group LLC	Crane 1	190.0	Steam-Coal	BGE	57.0	01-Jun-18
Avenue Capital Group LLC	Crane 2	195.0	Steam-Coal	BGE	55.4	01-Jun-18
Avenue Capital Group LLC	Crane GT1	14.0	CT-Other	BGE	50.9	01-Jun-18
Riverstone Holdings LLC	Bayonne Cogen Plant (CC)	158.0	Combined Cycle	PSEG	29.7	01-Jun-18
The AES Corporation	Killen 2	402.0	Steam-Coal	DAY	36.0	01-Jun-18
The AES Corporation	Killen CT	18.0	CT-Other	DAY	35.2	01-Jun-18
The AES Corporation	Stuart 2	202.0	Steam-Coal	DAY	47.7	01-Jun-18
The AES Corporation	Stuart 3	202.0	Steam-Coal	DAY	46.1	01-Jun-18
The AES Corporation	Stuart 4	202.0	Steam-Coal	DAY	44.0	01-Jun-18
The AES Corporation	Stuart Diesels 1-4	3.0	RICE-Oil	DAY	48.7	01-Jun-18
Vistra Energy Corp	Killen 2	198.0	Steam-Coal	DAY	36.0	01-Jun-18
Vistra Energy Corp	Killen CT	6.0	CT-Other	DAY	35.2	01-Jun-18
Vistra Energy Corp	Stuart 2	225.0	Steam-Coal	DAY	47.7	01-Jun-18
Vistra Energy Corp	Stuart 3	225.0	Steam-Coal	DAY	46.1	01-Jun-18
Vistra Energy Corp	Stuart 4	225.0	Steam-Coal	DAY	44.0	01-Jun-18
Vistra Energy Corp	Stuart Diesels 1-4	3.6	RICE-Oil	DAY	48.7	01-Jun-18
Public Service Enterprise Group Incorporated	Sewaren 1	104.0	Steam-Natural Gas	PSEG	69.6	06-Jun-18
Public Service Enterprise Group Incorporated	Sewaren 2	118.0	Steam-Natural Gas	PSEG	69.6	06-Jun-18
Public Service Enterprise Group Incorporated	Sewaren 3	107.0	Steam-Natural Gas	PSEG	68.7	06-Jun-18
Public Service Enterprise Group Incorporated	Sewaren 4	124.0	Steam-Natural Gas	PSEG	67.0	06-Jun-18
Dominion Resources, Inc.	Hurt NUG	83.0	Steam-Biomass	Dominion	24.2	24-Jul-18
The AES Corporation	Barbados AES Battery	1.0	Battery	PECO	9.7	29-Jul-18
Quasar Energy Group, LLC	Zanesville Landfill	0.9	RICE-Other	AEP	6.1	08-Sep-18
Exelon Corporation	Oyster Creek Nuclear Generating Station	614.5	Nuclear	JCPL	48.8	17-Sep-18
Total		4,894.2				

17 The Killen 2, Killen CT, Stuart 2, 3 and 4 and Stuart Diesels 1-4 units are jointly owned. The MW displayed in each row represents the individual company's share of the retiring unit.

Planned Generation Retirements

Table 12-9 shows that there are 12,468.0 MW of generation that have requested retirement after September 30, 2018, of which 6,791.0 MW (54.5 percent) are located in the ATSI Zone, 7,341.8 MW (58.9 percent) are coal fired steam units and 4,716.0 MW (37.8 percent) are nuclear units. The largest generator pending retirement is the 1,240 MW Perry U1 Nuclear Generating Unit located in the ATSI Zone.

Table 12-9 Planned retirement of PJM units: September 30, 2018

Unit	Zone	ICAP (MW)	Unit Type	Projected Deactivation Date
Northeastern Power NEPCO	PPL	52.0	Steam-Coal	27-Nov-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
Yorktown 1-2	Dominion	323.0	Steam-Coal	08-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
Hopewell James River Cogeneration	Dominion	89.0	Steam-Coal	31-Mar-19
BL England 2	AECO	155.0	Steam-Coal	30-Apr-19
Monmouth NUG landfill	JCPL	6.4	CT-Other	31-May-19
MH50 Markus Hook Co-gen	PECO	50.8	CT-Natural_Gas	01-Jun-19
Kimberly Clark Generator	PECO	3.3	Steam-Coal	01-Aug-19
Three Mile Island Unit 1 Nuclear Generating Station	Met-Ed	805.0	Nuclear	30-Sep-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
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
Eastlake 6	ATSI	24.0	CT-Other	01-Jun-21
Sammis Diesel	ATSI	13.0	RICE-Oil	01-Jun-21
Mansfield 1	ATSI	830.0	Steam-Coal	01-Jun-21
Mansfield 2	ATSI	830.0	Steam-Coal	01-Jun-21
Mansfield 3	ATSI	830.0	Steam-Coal	01-Jun-21
Beaver Valley U2 Nuclear Generating Unit	DLCO	885.0	Nuclear	31-Oct-21
Sammis 5	ATSI	290.0	Steam-Coal	01-Jun-22
Sammis 6	ATSI	600.0	Steam-Coal	01-Jun-22
Sammis 7	ATSI	600.0	Steam-Coal	01-Jun-22
Total		12,468.0		

Generation Queue

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.[18] 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 MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the market will result in the entry of new capacity to meet the needs of PJM market participants.

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. 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. In May 2012, the duration of the queue period was reset to six months, starting with Queue Y2. Queue AD2 began on October 1, 2017 and closed on March 31, 2018. Queue AE1 began on April 1, 2018 and closed on September 30, 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.[19] 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.[20]

The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result.[21] The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition from new generation investments are not created. 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.

Process Timelines

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 12-10 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.

18 See OATT Parts IV & VI.
19 See "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 13 (August 23, 2018) Section 3.7
20 PJM does not track the duration of suspensions or PJM termination of projects.
21 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).

In 2016, the PJM Earlier Queue Submitted Task Force stakeholder group made changes to the interconnection process to address some of the issues related to delays observed in the various stages of the study phase. The changes became effective with the AC2 Queue that closed on March 31, 2017. Until there has been additional time and queue processing to validate the effectiveness of these changes, the MMU recommends continuing 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.

Table 12-11 shows MW in queues by expected completion year and MW changes in the queue between December 31, 2017, and September 30, 2018, for ongoing projects, i.e. projects with the status active, under construction or suspended.[23] Projects that are already in service are not included here. Projects that have been withdrawn or removed from the queue are no longer included in the totals. The total MW in queues increased by 22,169.1 MW (28.0 percent) from 79,224.3 MW at the end of 2017 to 101,393.4 MW on September 30, 2018.

Table 12-10 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

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 September 30, 2018, 101,393.4 MW of capacity were in generation request queues for construction through 2029. 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.[22]

22 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>.

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

Table 12-11 Queue comparison by expected completion year (MW): December 31, 2017 and September 30, 2018[24]

Year	As of 12/31/2017	As of 9/30/2018	Year Change MW	Year Change 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	102.5	102.5	0.0	0.0%
2012	91.2	91.2	0.0	0.0%
2013	210.5	210.5	0.0	0.0%
2014	27.4	12.4	(15.0)	(54.7%)
2015	502.4	234.1	(268.3)	(53.4%)
2016	2,067.4	967.2	(1,100.2)	(53.2%)
2017	4,342.9	3,038.3	(1,304.5)	(30.0%)
2018	13,489.2	10,564.6	(2,924.6)	(21.7%)
2019	24,330.0	25,758.0	1,428.0	5.9%
2020	23,235.6	28,947.8	5,712.1	24.6%
2021	8,352.4	19,704.7	11,352.3	135.9%
2022	2,460.9	4,265.9	1,805.0	73.3%
2023	0.0	3,764.0	3,764.0	0.0%
2024	0.0	1,320.0	1,320.0	0.0%
2025	0.0	800.1	800.1	0.0%
2026	0.0	0.0	0.0	0.0%
2027	0.0	800.1	800.1	0.0%
2028	0.0	0.0	0.0	0.0%
2029	0.0	800.1	800.1	0.0%
Total	79,224.3	101,393.4	22,169.1	28.0%

Table 12-12 shows the project status changes in more detail and how scheduled queue capacity has changed between December 31, 2017, and September 30, 2018. For example, 29,541.3 MW entered the queue in the first nine months of 2018. Of those 29,541.3 MW, 7,372.3 MW have been withdrawn. Of the total 71,405.5 MW marked as active on December 31, 2017, 10,752.6 MW were withdrawn, 3,018.8 MW were suspended, 844.2 MW started construction, and 221.7 MW went into service by September 30, 2018. Analysis of projects that were suspended on December 31, 2017 show that 2,518.9 MW came out of suspension and are now active and 40.0 MW began construction in the first nine months of 2018.

24 Wind and solar capacity in Table 12-11 through Table 12-15 have not been adjusted to reflect derating.

Table 12-12 Change in project status (MW): December 31, 2017 to September 30, 2018

		Status at 9/30/2018				
Status as 12/31/2017	Total at 12/31/2017	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2018)	0.0	22,169.1	0.0	0.0	0.0	7,372.3
Active	71,405.5	56,568.3	221.7	844.2	3,018.8	10,752.6
In Service	52,043.5	0.0	52,042.6	0.0	0.0	0.9
Under Construction	18,813.2	20.0	7,373.6	10,928.7	224.0	266.9
Suspended	9,356.1	2,518.9	100.0	40.0	5,061.5	1,635.7
Withdrawn	322,847.7	0.0	0.0	0.0	0.0	322,847.7
Total	474,465.9	81,276.3	59,737.9	11,812.9	8,304.3	342,875.9

On September 30, 2018, 101,393.4 MW of capacity were in generation request queues in the status of active, suspended or under construction. Table 12-13 shows each status by unit type. Of the 81,276.3 MW in the status of Active on September 30, 2018, 31,804.8 MW (39.1 percent) were combined cycle projects. Of the 11,812.9 MW in the status of under construction, 8,011.6 MW (67.8 percent) were combined cycle projects.

Table 12-13 Current project status (MW) by unit type: September 30, 2018

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
Active	664.9	31,804.8	3,103.8	14.0	0.0	1.9	1,034.0	20.5	167.5	111.8	4.0	16.4	24,820.3	99.0	94.0	0.0	40.0	19,279.4	81,276.3
Suspended	66.3	6,481.1	268.8	0.0	0.0	0.0	0.0	0.0	0.0	79.6	0.0	0.0	444.5	0.0	0.0	0.0	16.0	948.0	8,304.3
Under Construction	86.1	8,011.6	205.0	0.0	3.2	0.0	0.0	22.7	0.0	41.2	0.0	0.0	488.7	48.0	0.0	0.0	62.5	2,843.9	11,812.9
Total	817.2	46,297.5	3,577.6	14.0	3.2	1.9	1,034.0	43.2	167.5	232.6	4.0	16.4	25,753.5	147.0	94.0	0.0	118.5	23,071.3	101,393.4

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 September 30, 2018, there were 50,201.7 MW of natural gas fired capacity active, suspended or under construction in PJM queues (including combined cycle units, CTs, RICE units, and natural gas fired steam units). As of September 30, 2018, there were only 147.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.

There are 7,341.8 MW of coal fired steam capacity and 366.8 MW of natural gas capacity slated for deactivation between September 30, 2018, and December 31, 2021 (See Table 12-9). 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.

Table 12-14 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 September 30, 2018, there are 101,393.4 MW of capacity in queues that are not yet in service or withdrawn, of which 8.2 percent are suspended, 11.7 percent are under construction and 80.1 percent have not begun construction.

Table 12-14 Capacity in PJM queues (MW): September 30, 2018[25]

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	1,040.0	2,046.4	0.0	0.0	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	0.0	23,313.3	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	420.0	267.5	560.0	0.0	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	500.0	85.2	0.0	0.0	4,445.0	5,030.2
V1 Expired 30-Apr-09	40.0	197.9	0.0	0.0	2,532.8	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	0.0	3,822.7	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	13.5	345.9	300.0	0.0	5,139.5	5,798.9
W2 Expired 31-Jul-10	10.0	289.2	62.5	23.0	3,018.7	3,403.4
W3 Expired 31-Oct-10	371.0	480.3	67.7	100.0	8,203.1	9,222.0
W4 Expired 31-Jan-11	7.4	1,101.8	399.9	415.0	3,698.2	5,622.3
X1 Expired 30-Apr-11	0.0	1,103.8	0.0	0.0	6,200.6	7,304.4
X2 Expired 31-Jul-11	0.0	3,544.4	187.5	585.0	5,578.4	9,895.2
X3 Expired 31-Oct-11	0.0	89.2	20.0	894.0	6,771.9	7,775.1
X4 Expired 31-Jan-12	0.0	1,929.4	1,019.5	0.0	2,419.4	5,368.3
Y1 Expired 30-Apr-12	106.0	1,797.5	452.0	0.0	5,721.7	8,077.2
Y2 Expired 31-Oct-12	378.3	1,051.8	387.1	229.0	9,247.5	11,293.7
Y3 Expired 30-Apr-13	0.0	626.3	1,004.2	0.0	4,609.2	6,239.6
Z1 Expired 31-Oct-13	713.0	1,247.0	2,127.8	39.8	3,997.2	8,124.8
Z2 Expired 30-Apr-14	305.6	2,272.4	585.0	52.9	2,949.9	6,165.8
AA1 Expired 31-Oct-14	3,171.4	753.8	1,618.9	683.1	5,771.5	11,998.7
AA2 Expired 30-Apr-15	4,403.5	476.9	700.7	2,371.0	8,114.2	16,066.3
AB1 Expired 31-Oct-15	9,127.4	706.5	234.4	1,235.3	9,149.0	20,452.6
AB2 Expired 31-Mar-16	9,756.7	122.5	55.0	183.6	5,099.6	15,217.4
AC1 Expired 30-Sep-16	12,513.9	103.2	51.5	1,263.7	6,143.3	20,075.6
AC2 Expired 30-Apr-17	5,351.7	80.0	0.6	23.9	7,165.5	12,621.6
AD1 Expired 30-Sep-17	9,365.1	6.2	0.0	0.0	2,075.9	11,447.2
AD2 Expired 31-Mar-18	12,632.6	0.0	0.0	0.0	7,848.4	20,481.0
AE1 Expired 30-Sep-18	10,529.1	0.0	0.0	0.0	726.3	11,255.4
Total	81,276.3	59,737.9	11,812.9	8,304.3	342,875.9	504,007.2

Table 12-15 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of September 30, 2018, 101,393.4 MW of capacity were in generation request queues for construction through 2029.[26] Table 12-15 also shows the planned retirements for each zone.

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

26 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 23,071.3 MW of wind resources and 25,753.5 MW of solar resources, the 101,393.4 MW currently under construction, suspended or active in the queue would be reduced to 65,354.2 MW.

Table 12-15 Queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): September 30, 2018[27]

LDA	Zone	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total Queue Capacity	Planned Retirments
EMAAC	AECO	50.0	1,748.6	388.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.0	0.0	48.3	0.0	0.0	0.0	0.0	619.0	2,854.3	155.0
	DPL	1.0	451.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.6	1,402.0	0.0	0.0	0.0	0.0	247.8	2,117.4	0.0
	JCPL	128.3	605.0	200.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	154.6	0.0	0.0	0.0	0.0	2,640.0	3,728.0	6.4
	PECO	0.0	982.0	0.0	0.0	0.0	0.0	0.0	0.0	94.0	0.0	4.0	0.0	18.0	0.0	0.0	0.0	0.0	0.0	1,098.0	54.1
	PSEG	2.0	3,710.5	0.0	0.0	0.0	1.3	0.0	0.0	0.0	0.0	0.0	0.0	85.4	0.0	0.0	0.0	0.0	0.0	3,799.2	0.0
	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	40.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0
	EMAAC Total	181.2	7,497.1	588.0	0.0	0.0	1.9	0.0	0.0	94.0	0.0	4.0	15.6	1,748.3	0.0	0.0	0.0	0.0	3,506.8	13,636.9	215.5
SWMAAC	BGE	0.1	0.0	144.6	14.0	0.0	0.0	0.0	0.0	45.5	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.5	135.0
	Pepco	0.0	1,197.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	76.3	0.0	0.0	0.0	0.0	0.0	1,273.4	0.0
	SWMAAC Total	0.1	1,197.1	144.6	14.0	0.0	0.0	0.0	0.0	45.5	1.3	0.0	0.0	76.3	0.0	0.0	0.0	0.0	0.0	1,478.9	135.0
WMAAC	Met-Ed	0.0	598.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	230.0	0.0	0.0	0.0	0.0	0.0	828.9	805.0
	PENELEC	0.0	1,348.0	531.8	0.0	0.0	0.0	0.0	0.0	0.0	119.6	0.0	0.0	246.9	0.0	0.0	0.0	0.0	290.3	2,536.6	110.0
	PPL	30.0	3,205.8	0.0	0.0	0.0	0.0	1,000.0	0.0	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	16.0	531.1	4,812.9	52.0
	WMAAC Total	30.0	5,152.7	531.8	0.0	0.0	0.0	1,000.0	0.0	0.0	119.6	0.0	0.0	506.9	0.0	0.0	0.0	16.0	821.4	8,178.4	967.0
Non-MAAC	AEP	104.0	8,016.0	413.0	0.0	3.2	0.0	34.0	0.0	28.0	12.0	0.0	0.8	6,894.0	101.0	30.0	0.0	40.0	6,519.3	22,195.2	0.0
	APS	145.5	6,325.7	120.0	0.0	0.0	0.0	0.0	15.0	0.0	99.7	0.0	0.0	830.8	0.0	0.0	0.0	0.0	1,184.4	8,721.1	1,278.0
	ATSI	8.8	4,386.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	940.9	0.0	0.0	0.0	0.0	816.1	6,221.7	6,791.0
	ComEd	232.9	7,006.8	1,238.0	0.0	0.0	0.0	0.0	22.7	0.0	0.0	0.0	0.0	1,679.5	0.0	64.0	0.0	0.0	6,899.7	17,143.6	0.0
	DAY	19.9	1,150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,136.5	12.0	0.0	0.0	0.0	100.0	2,418.4	0.0
	DEOK	19.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	380.0	20.0	0.0	0.0	0.0	0.0	419.8	0.0
	DLCO	20.0	0.0	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	245.0	1,777.0
	Dominion	55.0	5,566.1	194.2	0.0	0.0	0.0	0.0	5.5	0.0	0.0	0.0	0.0	11,215.5	14.0	0.0	0.0	62.5	3,223.7	20,336.5	1,304.5
	EKPC	0.0	0.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	325.0	0.0	0.0	0.0	0.0	0.0	398.0	0.0
	RMU	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
	Non-MAAC Total	605.9	32,450.6	2,313.2	0.0	3.2	0.0	34.0	43.2	28.0	111.7	0.0	0.8	23,422.1	147.0	94.0	0.0	102.5	18,743.1	78,099.3	11,150.5
	Total	817.2	46,297.5	3,577.6	14.0	3.2	1.9	1,034.0	43.2	167.5	232.6	4.0	16.4	25,753.5	147.0	94.0	0.0	118.5	23,071.3	101,393.4	12,468.0

Withdrawn Projects

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 are withdrawn. 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.[28] 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 12-16 and Table 12-17.

Table 12-16 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the 2,323 projects withdrawn, 1,188 (51.1 percent) were withdrawn before the system impact study was completed. Once an Interconnection Service Agreement (ISA) or a Wholesale Market Participation Agreement

27 This data includes only projects with a status of active, under construction, or suspended.
28 See PJM. "Manual 14B: PJM Region Transmission Planning Process," Rev. 42 (August 23, 2018), p.82.

(WMPA) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted.[29] [30] Of the 2,323 projects withdrawn, 442 (19.0 percent) were withdrawn after the completion of a Construction Service Agreement.

Table 12-16 Last milestone at time of withdrawal: January 1997 through September 2018

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	376	16.2%	99	875
Feasibility Study	759	32.7%	274	1,633
System Impact Study	469	20.2%	751	3,248
Facilities Study	277	11.9%	1,073	3,454
Construction Service Agreement (CSA) or beyond	442	19.0%	1,261	4,249
Total	2,323	100.0%		

Average Time in Queue

Table 12-17 shows 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 1,017 days, or 2.8 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 617 days, or 1.7 years, between entering a queue and withdrawing.

Table 12-17 Project queue times by status (days): September 30, 2018[31]

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	501	609	0	4,211
In-Service	1,017	728	0	4,024
Suspended	1,500	905	366	4,177
Under Construction	1,820	1,073	486	4,933
Withdrawn	617	689	0	4,249

Table 12-18 presents information on the time in the stages of the queue for those projects not yet in service or already withdrawn. Of the 841 projects in the queue as of September 30, 2018, 236 (28.1 percent) had a completed feasibility study and 279 (33.2 percent) were under construction.

Table 12-18 Project queue times by milestone (days): September 30, 2018

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	117	13.9%	140	368
Feasibility Study	236	28.1%	424	1,347
System Impact Study	174	20.7%	811	3,570
Facilities Study	35	4.2%	1,365	3,654
Construction Service Agreement (CSA) or beyond	279	33.2%	1,566	5,116
Total	841	100.0%		

Completion Rates

The probability of a project going into service increases as each step of the planning process is completed. Table 12-19 shows the historic completion rates (MW energy) by unit type for projects that have completed the system impact study, facilities study and construction service agreement stages. For example, of all wind projects to ever enter the queue and complete the system impact study stage, 15.9 percent of the queued MW have gone into service. The completion rate for wind projects increases to 31.1 percent when wind projects complete the facility study agreement, and further increases to 48.9 percent when wind projects complete the construction service agreement.

29 "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).

30 See PJM. "Manual 14C: Generation and Transmission Interconnection Facility Construction," Rev. 13 (August 23, 2018).

31 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.

Table 12-19 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: January 1997 through September 2018

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)
Battery	23.3%	44.3%	60.1%
CC	30.7%	50.8%	85.6%
CT - Natural Gas	80.3%	83.3%	87.3%
CT - Oil	35.6%	60.3%	90.9%
CT - Other	12.5%	19.0%	30.2%
Fuel Cell	41.6%	43.5%	43.5%
Hydro - Pumped Storage	100.0%	100.0%	100.0%
Hydro - Run of River	40.8%	56.9%	62.3%
Nuclear	34.9%	41.8%	51.2%
RICE - Natural Gas	38.2%	58.6%	70.7%
RICE - Oil	30.6%	55.9%	55.9%
RICE - Other	90.6%	90.6%	91.3%
Solar	15.1%	27.6%	35.4%
Steam - Coal	13.3%	24.8%	36.8%
Steam - Natural Gas	96.5%	96.5%	96.5%
Steam - Oil	0.0%	0.0%	0.0%
Steam - Other	27.9%	37.2%	45.2%
Wind	15.9%	31.1%	48.9%

Queue Analysis by Fuel

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 12-20 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 1,317 projects entered in 2015, 2016, 2017 and the first nine months of 2018, 1,037 projects, 78.7 percent, were renewable. Of the 254 projects entered in the first nine months of 2018, 221 projects, 87.0 percent, were renewable.

Table 12-20 Number of projects entered in the queue: September 30, 2018

	Fuel Group			
Year Entered	Nuclear	Renewable	Traditional	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	300	53	355
2018	1	221	32	254
Total	70	2,451	1,448	3,969

Renewable projects comprise the majority of projects entered in the queue, as well as what is currently active in the queue. Renewable projects make up 50.0 percent of the nameplate MW currently active, suspended or under construction in the queue (Table 12-21).

Table 12-21 Queue details by fuel group: September 30, 2018

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	9	1.1%	167.5	0.2%
Renewable	639	76.0%	50,721.1	50.0%
Traditional	193	22.9%	50,504.8	49.8%
Total	841	100.0%	101,393.4	100.0%

Queue Analysis by Unit Type and Project Classification

Table 12-22 shows the current status of all generation queue projects by unit type and project classification from January 1, 1997, through September 30, 2018. As of September 30, 2018, 3,969 projects, representing 504,007.2 MW, have entered the queue process since its inception. Of those, 805 projects, representing 59,737.9 MW, went into service. Of the projects that entered the queue process, 2,323 projects, representing 342,875.9 MW (68.0 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 total of 3,217 projects have been classified as new generation and 752 projects have been classified as upgrades. Wind, solar and natural gas projects have accounted for 3,130 projects, or 78.9 percent, of all 3,969 generation queue projects.

Table 12-22 Status of all generation queue projects: January 1997 through September 2018

		Number of Projects																		
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
In Service	New Generation	18	53	48	10	24	3	0	11	2	8	0	55	127	8	5	0	3	76	451
	Upgrade	4	73	89	15	5	0	2	16	41	8	1	14	16	51	7	0	7	5	354
Under Construction	New Generation	25	9	1	0	1	0	0	2	0	3	0	0	21	0	0	0	0	17	79
	Upgrade	1	12	1	0	0	0	0	0	0	0	0	0	3	2	0	0	1	2	22
Suspended	New Generation	7	8	3	0	0	0	0	0	0	4	0	0	32	0	0	0	1	8	63
	Upgrade	2	6	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	11
Withdrawn	New Generation	95	401	15	9	81	18	0	39	9	18	12	14	919	55	1	0	34	398	2,118
	Upgrade	14	80	5	13	13	2	0	4	9	0	2	2	25	14	0	0	2	20	205
Active	New Generation	19	37	9	1	0	9	3	1	1	6	0	2	350	0	0	0	0	68	506
	Upgrade	10	43	28	0	0	0	1	1	8	1	1	3	35	5	3	0	1	20	160
Total Projects	New Generation	164	508	76	20	106	30	3	53	12	39	12	71	1,449	63	6	0	38	567	3,217
	Upgrade	31	214	124	28	18	2	3	21	58	9	4	19	80	72	10	0	11	48	752

Table 12-23 shows the totals in Table 12-22 by share of classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 76.2 percent of all hydro – run of river projects classified as upgrades are currently in service in PJM, 19.0 percent of hydro – run of river upgrades were withdrawn and 4.8 percent of hydro – run of river upgrades are active in the queue.

Table 12-23 Status of all generation queue projects as a percent of total projects by classification: January 1997 through September 2018

	Percent of Projects																			
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
In Service	New Generation	11.0%	10.4%	63.2%	50.0%	22.6%	10.0%	0.0%	20.8%	16.7%	20.5%	0.0%	77.5%	8.8%	12.7%	83.3%	0.0%	7.9%	13.4%	14.0%
	Upgrade	12.9%	34.1%	71.8%	53.6%	27.8%	0.0%	66.7%	76.2%	70.7%	88.9%	25.0%	73.7%	20.0%	70.8%	70.0%	0.0%	63.6%	10.4%	47.1%
Under Construction	New Generation	15.2%	1.8%	1.3%	0.0%	0.9%	0.0%	0.0%	3.8%	0.0%	7.7%	0.0%	0.0%	1.4%	0.0%	0.0%	0.0%	0.0%	3.0%	2.5%
	Upgrade	3.2%	5.6%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.8%	2.8%	0.0%	0.0%	9.1%	4.2%	2.9%
Suspended	New Generation	4.3%	1.6%	3.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.3%	0.0%	0.0%	2.2%	0.0%	0.0%	0.0%	2.6%	1.4%	2.0%
	Upgrade	6.5%	2.8%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	0.0%	2.1%	1.5%
Withdrawn	New Generation	57.9%	78.9%	19.7%	45.0%	76.4%	60.0%	0.0%	73.6%	75.0%	46.2%	100.0%	19.7%	63.4%	87.3%	16.7%	0.0%	89.5%	70.2%	65.8%
	Upgrade	45.2%	37.4%	4.0%	46.4%	72.2%	100.0%	0.0%	19.0%	15.5%	0.0%	50.0%	10.5%	31.3%	19.4%	0.0%	0.0%	18.2%	41.7%	27.3%
Active	New Generation	11.6%	7.3%	11.8%	5.0%	0.0%	30.0%	100.0%	1.9%	8.3%	15.4%	0.0%	2.8%	24.2%	0.0%	0.0%	0.0%	0.0%	12.0%	15.7%
	Upgrade	32.3%	20.1%	22.6%	0.0%	0.0%	0.0%	33.3%	4.8%	13.8%	11.1%	25.0%	15.8%	43.8%	6.9%	30.0%	0.0%	9.1%	41.7%	21.3%

Table 12-24 shows the nameplate generating capacity of projects in the PJM generation queue by technology type and project classification. For example, the 398 new generation wind projects that have been withdrawn from the queue as of September 30, 2018, (as shown in Table 12-22) constitute 65,113.0 MW of nameplate capacity. The 481 new generation and upgrade combined cycle projects that have been withdrawn in the same time period constitute 201,325.9 MW of nameplate capacity.

Table 12-24 Status of all generation capacity (MW) in the PJM generation queue: January 1997 through September 2018

	Project MW																			
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
In Service	New Generation	156.4	26,396.0	6,600.5	676.5	148.2	1.9	0.0	471.5	1,639.0	118.2	0.0	440.1	1,299.3	1,343.0	723.0	0.0	60.0	7,191.1	47,264.7
	Upgrade	42.4	4,990.8	2,558.5	127.8	12.3	0.0	356.0	373.6	2,282.8	15.7	23.3	49.9	19.4	883.5	131.5	0.0	605.3	0.5	12,473.3
Under Construction	New Generation	86.1	6,910.5	205.0	0.0	3.2	0.0	0.0	22.7	0.0	41.2	0.0	0.0	474.8	0.0	0.0	0.0	0.0	2,811.9	10,555.4
	Upgrade	0.0	1,101.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.9	48.0	0.0	0.0	62.5	32.0	1,257.5
Suspended	New Generation	43.3	5,721.0	68.8	0.0	0.0	0.0	0.0	0.0	0.0	79.6	0.0	0.0	424.7	0.0	0.0	0.0	16.0	931.7	7,285.1
	Upgrade	23.0	760.1	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.8	0.0	0.0	0.0	0.0	16.3	1,019.2
Withdrawn	New Generation	1,391.3	191,371.8	1,556.0	1,721.0	1,244.2	3.8	0.0	1,986.9	8,161.0	288.4	63.9	77.0	21,298.8	33,511.6	27.0	0.0	1,035.8	65,113.0	328,851.4
	Upgrade	301.1	9,954.2	273.5	589.0	72.5	0.9	0.0	57.1	916.0	0.0	13.0	6.0	502.1	865.0	0.0	0.0	37.1	437.0	14,024.5
Active	New Generation	423.9	28,459.6	1,633.8	14.0	0.0	1.9	1,000.0	15.0	28.0	110.2	0.0	11.6	22,972.6	0.0	0.0	0.0	0.0	17,663.9	72,334.4
	Upgrade	241.0	3,345.2	1,470.0	0.0	0.0	0.0	34.0	5.5	139.5	1.6	4.0	4.8	1,847.8	99.0	94.0	0.0	40.0	1,615.5	8,941.8
Total Projects	New Generation	2,100.9	258,858.9	10,064.1	2,411.5	1,395.6	7.6	1,000.0	2,496.1	9,828.0	637.6	63.9	528.7	46,470.1	34,854.6	750.0	0.0	1,111.8	93,711.6	466,291.0
	Upgrade	607.5	20,151.4	4,502.0	716.8	84.8	0.9	390.0	436.2	3,338.3	17.3	40.3	60.7	2,403.0	1,895.5	225.5	0.0	744.9	2,101.3	37,716.3

Table 12-25 shows the MW totals in Table 12-24 by share by classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 69.5 percent of wind project MW classified as new generation have been withdrawn from the queue between January 1, 1997, and September 30, 2018.

Table 12-25 Status of all generation queue projects as percent of total MW in project classification: January 1997 through September 2018

		Percent of Total Projects by Classification																		
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
In Service	New Generation	7.4%	10.2%	65.6%	28.1%	10.6%	25.5%	0.0%	18.9%	16.7%	18.5%	0.0%	83.2%	2.8%	3.9%	96.4%	0.0%	5.4%	7.7%	10.1%
	Upgrade	7.0%	24.8%	56.8%	17.8%	14.5%	0.0%	91.3%	85.6%	68.4%	90.8%	57.8%	82.2%	0.8%	46.6%	58.3%	0.0%	81.3%	0.0%	33.1%
Under Construction	New Generation	4.1%	2.7%	2.0%	0.0%	0.2%	0.0%	0.0%	0.9%	0.0%	6.5%	0.0%	0.0%	1.0%	0.0%	0.0%	0.0%	0.0%	3.0%	2.3%
	Upgrade	0.0%	5.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	2.5%	0.0%	0.0%	8.4%	1.5%	3.3%
Suspended	New Generation	2.1%	2.2%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	12.5%	0.0%	0.0%	0.9%	0.0%	0.0%	0.0%	1.4%	1.0%	1.6%
	Upgrade	3.8%	3.8%	4.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	0.8%	2.7%
Withdrawn	New Generation	66.2%	73.9%	15.5%	71.4%	89.2%	49.7%	0.0%	79.6%	83.0%	45.2%	100.0%	14.6%	45.8%	96.1%	3.6%	0.0%	93.2%	69.5%	70.5%
	Upgrade	49.6%	49.4%	6.1%	82.2%	85.5%	100.0%	0.0%	13.1%	27.4%	0.0%	32.3%	9.9%	20.9%	45.6%	0.0%	0.0%	5.0%	20.8%	37.2%
Active	New Generation	20.2%	11.0%	16.2%	0.6%	0.0%	24.7%	100.0%	0.6%	0.3%	17.3%	0.0%	2.2%	49.4%	0.0%	0.0%	0.0%	0.0%	18.8%	15.5%
	Upgrade	39.7%	16.6%	32.7%	0.0%	0.0%	0.0%	8.7%	1.3%	4.2%	9.2%	9.9%	7.9%	76.9%	5.2%	41.7%	0.0%	5.4%	76.9%	23.7%

Table 12-26 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 93.9 percent of all new projects entering the generation queue have been either combined cycle (30.9 percent), wind (21.5 percent) or solar projects (41.4 percent).

Table 12-26 Queue project MW by unit type and queue entry year: January 1997 through September 2018

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
1997	0.0	4,148.0	321.0	315.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	4,840.0
1998	0.0	7,006.0	1,775.0	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	8,781.0
1999	0.0	29,412.7	2,412.1	0.0	10.0	0.0	0.0	196.0	45.0	0.0	0.0	0.0	0.0	47.0	0.0	0.0	525.0	115.4	32,763.2
2000	0.0	21,144.8	493.6	31.5	8.8	0.0	0.0	0.0	95.0	0.0	0.0	1.2	0.0	37.0	2.5	0.0	0.0	95.6	21,909.9
2001	0.0	25,411.7	264.0	0.0	0.0	0.0	0.0	107.0	90.0	0.0	0.0	15.6	0.0	1,244.6	10.0	0.0	0.0	252.9	27,395.8
2002	0.0	4,154.0	11.7	0.0	70.5	0.0	0.0	293.0	236.0	8.0	23.3	4.5	0.0	1,895.0	0.0	0.0	0.0	790.9	7,486.9
2003	0.0	2,361.4	10.0	8.0	0.8	0.0	0.0	2.0	0.0	29.0	0.0	27.5	0.0	522.0	0.0	0.0	165.0	1,002.9	4,128.6
2004	0.0	3,610.0	43.3	20.0	49.1	0.0	0.0	0.0	1,911.0	0.0	35.5	17.5	0.0	1,187.0	0.0	0.0	0.0	1,613.7	8,487.1
2005	0.0	5,824.6	1,196.0	281.0	51.4	0.0	340.0	174.2	242.0	21.5	0.0	65.1	0.0	6,360.0	0.0	0.0	24.0	6,020.0	20,599.9
2006	0.0	4,188.1	454.3	607.5	73.1	0.0	0.0	159.0	6,894.0	0.0	0.0	93.0	0.0	9,586.0	0.0	0.0	258.5	7,650.7	29,964.2
2007	0.0	14,130.6	941.2	215.9	149.5	0.0	16.0	255.4	368.0	0.0	0.0	56.5	3.3	9,078.0	190.0	0.0	50.5	18,525.6	43,980.4
2008	121.0	26,001.0	129.7	1,113.0	488.8	0.0	0.0	1,254.5	105.0	6.0	0.0	32.0	66.3	1,198.0	0.0	0.0	192.3	11,199.7	41,907.3
2009	34.0	5,548.4	14.0	66.0	214.2	0.0	0.0	133.9	1,933.8	4.5	16.0	15.2	636.5	1,273.0	5.5	0.0	148.0	6,672.6	16,715.6
2010	72.4	9,185.4	176.0	7.9	117.3	0.0	0.0	132.6	426.0	0.0	2.4	57.8	3,690.0	64.0	0.0	0.0	173.5	9,940.4	24,045.7
2011	24.1	20,354.5	29.5	0.0	174.6	0.0	0.0	30.0	182.0	0.0	14.0	75.3	2,022.9	357.0	0.0	0.0	49.0	5,576.4	28,889.3
2012	142.6	18,014.8	282.1	42.5	48.4	0.0	0.0	11.8	369.0	37.2	0.0	4.0	286.6	1,837.0	0.0	0.0	143.1	1,529.8	22,748.8
2013	217.4	11,168.1	526.8	5.0	11.2	0.0	0.0	89.4	102.0	59.7	0.0	1.6	231.7	158.0	40.0	0.0	44.7	1,407.9	14,063.4
2014	246.9	11,769.5	1,532.5	401.0	7.7	0.0	0.0	60.5	0.0	48.0	0.0	17.7	1,445.7	1,730.5	27.0	0.0	43.1	1,763.7	19,093.8
2015	546.9	27,540.8	1,324.5	0.0	0.9	2.3	34.0	0.0	0.0	320.4	13.0	31.4	2,931.6	47.0	606.5	0.0	0.0	2,160.6	35,559.7
2016	111.1	18,804.5	1,392.0	0.0	0.0	3.4	0.0	12.5	50.3	23.5	0.0	38.9	11,771.5	80.0	77.0	0.0	0.0	3,467.5	35,832.2
2017	24.6	5,448.1	702.0	0.0	4.1	2.9	0.0	20.5	39.1	97.1	0.0	33.8	13,899.0	14.0	17.0	0.0	0.0	5,602.0	25,904.3
2018	1,167.4	3,783.4	534.8	14.0	0.0	0.0	1,000.0	0.0	28.1	0.0	0.0	0.8	11,887.9	29.0	0.0	0.0	40.0	10,424.6	28,910.0
Total	2,708.4	279,010.3	14,566.1	3,128.3	1,480.3	8.5	1,390.0	2,932.3	13,166.3	654.9	104.2	589.4	48,873.1	36,750.1	975.5	0.0	1,856.7	95,812.9	504,007.2

Combined Cycle Project Analysis

Table 12-27 shows the status of all combined cycle projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2018, by zone. Of the 115 combined cycle projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 47 projects (40.9 percent) are located within AEP, ComEd and APS.

Table 12-27 Status of all combined cycle queue projects by zone (number of projects): January 1997 through September 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	4	1	2	2	1	0	2	0	6	2	0	7	3	4	1	3	9	5	0	53
	Upgrade	2	8	5	1	0	3	0	0	0	12	5	0	4	1	9	3	2	5	13	0	73
Under Construction	New Generation	1	0	1	0	0	0	0	0	0	1	0	0	0	1	1	1	1	1	1	0	9
	Upgrade	0	0	0	2	0	1	0	0	0	0	0	0	0	1	3	1	1	2	1	0	12
Suspended	New Generation	1	2	3	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	8
	Upgrade	0	0	3	0	0	0	0	0	0	0	1	0	0	0	0	0	2	0	0	0	6
Withdrawn	New Generation	19	18	40	11	8	9	0	1	2	16	17	3	24	25	43	39	33	39	52	2	401
	Upgrade	6	7	5	3	0	3	0	1	0	7	4	0	5	7	3	5	3	6	15	0	80
Active	New Generation	2	7	4	4	0	9	1	0	0	3	0	0	1	0	0	0	0	2	4	0	37
	Upgrade	3	8	6	2	0	3	0	0	0	6	0	0	5	2	1	2	1	3	1	0	43
Total Projects	New Generation	24	31	49	17	10	19	1	3	2	26	19	3	32	29	48	42	38	51	62	2	508
	Upgrade	11	23	19	8	0	10	0	1	0	25	10	0	14	11	16	11	9	16	30	0	214

Table 12-28 shows the status of all combined cycle projects by MW that entered PJM generation queues from January 1, 1997 through September 30, 2018, by zone. Of the 46,297.5 MW of combined cycle projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 21,348.5 MW (46.1 percent) are located within AEP, ComEd and APS.

Table 12-28 Status of all combined cycle queue projects by zone (MW): January 1997 through September 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	650.0	3,032.0	525.0	1,599.0	266.0	600.0	0.0	533.0	0.0	4,173.1	319.2	0.0	1,665.8	2,107.0	1,905.0	850.0	1,540.5	4,750.0	1,880.5	0.0	26,396.0
	Upgrade	220.0	230.0	670.0	5.0	0.0	621.0	0.0	0.0	0.0	913.0	102.0	0.0	110.0	10.0	853.5	92.3	89.1	229.0	845.9	0.0	4,990.8
Under Construction	New Generation	452.0	0.0	930.0	0.0	0.0	0.0	0.0	0.0	0.0	1,681.0	0.0	0.0	0.0	450.0	760.0	1,050.0	19.5	1,000.0	568.0	0.0	6,910.5
	Upgrade	0.0	0.0	0.0	301.0	0.0	12.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.0	155.0	50.0	64.5	483.0	0.0	0.0	1,101.1
Suspended	New Generation	235.0	1,579.0	2,850.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	163.0	894.0	0.0	0.0	0.0	5,721.0
	Upgrade	0.0	0.0	165.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	451.0	0.0	0.0	0.0	0.0	0.0	144.1	0.0	0.0	0.0	760.1
Withdrawn	New Generation	6,909.4	11,249.5	16,982.1	6,301.0	3,122.1	4,631.0	0.0	134.5	665.0	10,421.0	5,436.4	991.8	12,552.6	13,001.0	23,340.0	15,931.0	20,414.2	16,785.7	22,496.7	6.9	191,371.8
	Upgrade	115.4	711.0	579.0	86.0	0.0	1,375.0	0.0	36.0	0.0	305.3	668.0	0.0	253.0	1,742.0	240.0	1,040.6	85.0	500.0	2,217.9	0.0	9,954.2
Active	New Generation	946.0	5,595.0	1,626.0	4,047.0	0.0	6,549.2	1,150.0	0.0	0.0	3,500.0	0.0	0.0	440.0	0.0	0.0	0.0	0.0	1,515.0	3,091.4	0.0	28,459.6
	Upgrade	115.6	842.0	754.7	38.0	0.0	445.0	0.0	0.0	0.0	385.1	0.0	0.0	165.0	113.9	67.0	85.0	75.0	207.8	51.1	0.0	3,345.2
Total Projects	New Generation	9,192.4	21,455.5	22,913.1	11,947.0	3,388.1	11,780.2	1,150.0	667.5	665.0	19,775.1	5,755.6	991.8	14,658.4	15,558.0	26,005.0	17,994.0	22,868.2	24,050.7	28,036.6	6.9	258,858.9
	Upgrade	451.0	1,783.0	2,168.7	430.0	0.0	2,453.6	0.0	36.0	0.0	1,603.4	1,221.0	0.0	528.0	1,900.9	1,315.5	1,267.9	457.7	1,419.8	3,114.9	0.0	20,151.4

Combustion Turbine – Natural Gas Project Analysis

Table 12-29 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2018, by zone. Of the 43 combustion turbine natural gas projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 24 projects (55.8 percent) are located within AEP, ComEd and APS.

Table 12-29 Status of all combustion turbine – natural gas generation queue projects by zone (number of projects): January 1997 through September 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	5	0	6	0	3	0	0	0	0	2	7	0	3	0	2	5	2	4	9	0	48
	Upgrade	4	7	5	1	0	9	6	0	0	24	7	0	0	1	2	2	3	4	14	0	89
Under Construction	New Generation	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	3
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1
Withdrawn	New Generation	1	3	0	0	0	1	0	0	0	1	0	0	0	0	1	2	0	1	5	0	15
	Upgrade	1	1	0	1	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	5
Active	New Generation	1	1	0	0	1	2	0	0	0	2	0	1	0	0	0	1	0	0	0	0	9
	Upgrade	1	1	6	1	0	14	0	0	0	5	0	0	0	0	0	0	0	0	0	0	28
Total Projects	New Generation	7	4	6	0	4	3	0	0	1	5	7	1	3	0	3	11	2	5	14	0	76
	Upgrade	6	9	11	3	0	23	6	0	0	29	7	0	2	2	2	3	3	4	14	0	124

Table 12-30 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation queues from January 1, 1997 through September 30, 2018, by zone. Of the 3,577.6 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, 1,771.0 MW (49.5 percent) are located within AEP, ComEd and APS.

Table 12-30 Status of all combustion turbine – natural gas queue projects by zone (MW): January 1997 through September 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	360.7	0.0	1,176.0	0.0	23.0	0.0	0.0	0.0	0.0	1,015.0	1,491.0	0.0	522.1	0.0	559.0	371.9	5.0	150.9	925.9	0.0	6,600.5
	Upgrade	43.7	190.0	187.7	40.0	0.0	257.0	60.0	0.0	0.0	887.7	321.0	0.0	0.0	34.1	13.0	25.0	32.0	252.3	215.0	0.0	2,558.5
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.0
	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
Suspended	New Generation	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	68.8	0.0	0.0	0.0	0.0	68.8
	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	0.0	0.0	0.0	0.0	200.0
Withdrawn	New Generation	7.5	66.0	0.0	0.0	0.0	10.0	0.0	0.0	0.0	54.0	0.0	0.0	0.0	0.0	0.5	258.0	0.0	19.9	1,140.1	0.0	1,556.0
	Upgrade	7.5	6.0	0.0	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	235.0	0.0	0.0	0.0	0.0	273.5
Active	New Generation	230.0	394.0	0.0	0.0	144.6	230.0	0.0	0.0	0.0	99.2	0.0	73.0	0.0	0.0	0.0	463.0	0.0	0.0	0.0	0.0	1,633.8
	Upgrade	158.0	19.0	120.0	70.0	0.0	1,008.0	0.0	0.0	0.0	95.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,470.0
Total Projects	New Generation	598.2	460.0	1,176.0	0.0	167.6	240.0	0.0	0.0	205.0	1,168.2	1,491.0	73.0	522.1	0.0	559.5	1,161.7	5.0	170.8	2,066.0	0.0	10,064.1
	Upgrade	209.2	215.0	307.7	135.0	0.0	1,265.0	60.0	0.0	0.0	982.7	321.0	0.0	200.0	34.1	13.0	260.0	32.0	252.3	215.0	0.0	4,502.0

Wind Project Analysis

Table 12-31 shows the status of all wind generation projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2018, by zone. Of the 80 wind projects to achieve in service status, 46 projects (57.5 percent) are located within AEP, ComEd and APS. Of the 116 wind projects currently active, suspended or under construction in the PJM generation queue, 88 projects (75.9 percent) are located within AEP, ComEd and APS.

Table 12-31 Status of all wind generation queue projects by zone (number of projects): January 1997 through September 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	13	14	0	0	17	0	0	0	0	0	0	0	0	0	23	0	8	0	0	76
	Upgrade	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	3	0	0	0	0	5
Under Construction	New Generation	0	2	4	0	0	6	0	0	0	4	0	0	0	0	0	1	0	0	0	0	17
	Upgrade	0	0	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	2
Suspended	New Generation	0	3	3	0	0	0	0	0	0	1	0	0	0	0	0	1	0	0	0	0	8
	Upgrade	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Withdrawn	New Generation	15	91	40	8	0	95	14	0	0	18	10	1	0	0	0	63	0	42	1	0	398
	Upgrade	1	0	6	0	0	3	0	0	0	2	0	0	0	0	0	6	0	2	0	0	20
Active	New Generation	2	25	4	3	0	22	1	0	0	3	1	0	2	0	0	0	0	5	0	0	68
	Upgrade	1	3	4	0	0	10	0	0	0	0	0	0	0	0	0	2	0	0	0	0	20
Total Projects	New Generation	18	134	65	11	0	140	15	0	0	26	11	1	2	0	0	88	0	55	1	0	567
	Upgrade	2	3	12	0	0	15	0	0	0	3	0	0	0	0	0	11	0	2	0	0	48

Table 12-32 shows the status of all wind projects by MW that entered PJM generation queues from January 1, 1997 through September 30, 2018, by zone. Of the 7,191.6 MW of wind generation capacity to achieve the in service status, 5,956.2 MW (82.8 percent) of nameplate capacity is located within AEP, ComEd and APS. Of the 23,071.3 MW of wind generation capacity currently active, suspended or under construction in the PJM generation queue, 14,603.3 MW of generation capacity (63.3 percent) is located within AEP, ComEd and APS.

Table 12-32 Status of all wind generation queue projects by zone (MW): January 1997 through September 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	2,538.7	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	1,000.9	0.0	226.5	0.0	0.0	7,191.1
	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	0.5	0.0	0.0	0.0	0.0	0.5
Under Construction	New Generation	0.0	450.0	348.6	0.0	0.0	1,228.5	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	2,811.9
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.0
Suspended	New Generation	0.0	380.0	375.1	0.0	0.0	0.0	0.0	0.0	0.0	76.6	0.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0	0.0	0.0	931.7
	Upgrade	0.0	0.0	16.3	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	16.3
Withdrawn	New Generation	3,626.4	18,670.8	3,052.1	1,295.6	0.0	22,521.7	2,028.0	0.0	0.0	2,588.1	2,816.8	150.3	0.0	0.0	0.0	5,277.0	0.0	3,066.3	20.0	0.0	65,113.0
	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	243.4	0.0	6.0	0.0	0.0	437.0
Active	New Generation	614.0	5,189.3	350.0	816.1	0.0	4,775.5	100.0	0.0	0.0	2,400.3	247.8	0.0	2,640.0	0.0	0.0	0.0	0.0	531.1	0.0	0.0	17,663.9
	Upgrade	5.0	500.0	94.4	0.0	0.0	895.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	120.3	0.0	0.0	0.0	0.0	1,615.5
Total Projects	New Generation	4,247.9	27,228.8	5,129.8	2,111.7	0.0	30,939.1	2,128.0	0.0	0.0	5,779.8	3,064.6	150.3	2,640.0	0.0	0.0	6,447.9	0.0	3,823.9	20.0	0.0	93,711.6
	Upgrade	5.0	500.0	210.7	0.0	0.0	901.4	0.0	0.0	0.0	114.0	0.0	0.0	0.0	0.0	0.0	364.2	0.0	6.0	0.0	0.0	2,101.3

Solar Project Analysis

Table 12-33 shows the status of all solar generation projects by number of projects that entered PJM generation queues from January 1, 1997, through September 30, 2018, by zone. Of the 143 solar projects to achieve in service status, 9 projects (6.3 percent) are located within AEP, ComEd and APS. Of the 403 solar projects currently active, suspended or under construction in the PJM generation queue, 127 projects (31.5 percent) are located within AEP, ComEd and APS.

Table 12-33 Status of all solar generation queue projects by zone (number of projects): January 1997 through September 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	17	9	0	41	0	1	0	0	2	39	0	127
	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	0	0	0	0	0	4	4	0	5	0	0	0	0	0	6	0	21
	Upgrade	0	0	0	0	0	0	0	0	0	2	1	0	0	0	0	0	0	0	0	0	3
Suspended	New Generation	0	3	19	0	0	0	1	0	0	2	0	0	5	0	0	1	0	0	1	0	32
	Upgrade	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1
Withdrawn	New Generation	159	71	58	8	12	27	14	12	0	137	114	3	167	12	6	12	13	27	67	0	919
	Upgrade	2	2	1	0	0	2	0	0	0	8	1	0	8	0	0	0	0	0	1	0	25
Active	New Generation	10	75	9	7	0	19	11	3	1	136	41	5	4	5	1	4	6	2	10	1	350
	Upgrade	0	5	1	1	0	0	1	2	1	19	1	0	1	2	0	0	0	1	0	0	35
Total Projects	New Generation	176	154	91	15	13	47	27	15	1	296	168	8	222	17	8	17	19	31	123	1	1,449
	Upgrade	2	7	2	1	0	2	1	2	1	32	11	0	15	2	0	0	0	1	1	0	80

Table 12-34 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997 through September 30, 2018, by zone. Of the 1,318.7 MW of solar generation capacity to achieve in service status, 76.7 MW (5.8 percent) of nameplate capacity is located within AEP, ComEd and APS. Of the 25,753.5 MW of solar generation capacity currently active, suspended or under construction in the PJM generation queue, 9,404.3 MW of generation capacity (36.5 percent) is located within AEP, ComEd and APS.

Table 12-34 Status of all solar generation queue projects by zone (MW): January 1997 through September 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	546.2	118.4	0.0	285.3	0.0	3.3	0.0	0.0	15.0	193.5	0.0	1,299.3
	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	0.0	0.0	0.0	0.0	0.0	295.8	37.0	0.0	81.9	0.0	0.0	0.0	0.0	0.0	30.1	0.0	474.8
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.9
Suspended	New Generation	0.0	20.0	313.3	0.0	0.0	0.0	20.0	0.0	0.0	24.8	0.0	0.0	37.6	0.0	0.0	3.0	0.0	0.0	6.0	0.0	424.7
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.8
Withdrawn	New Generation	1,665.3	3,261.6	1,486.4	216.1	53.3	1,338.8	523.9	279.4	0.0	7,867.0	1,516.7	189.9	1,348.8	467.0	51.4	121.7	175.8	283.7	451.9	0.0	21,298.8
	Upgrade	10.0	106.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	341.0	0.0	0.0	23.8	0.0	0.0	0.0	0.0	0.0	1.3	0.0	502.1
Active	New Generation	48.3	6,497.0	432.5	920.9	0.0	1,679.5	1,096.5	295.0	11.7	9,647.2	1,345.0	325.0	26.6	190.0	18.0	243.9	76.3	30.0	49.3	40.0	22,972.6
	Upgrade	0.0	357.0	75.0	20.0	0.0	0.0	20.0	85.0	8.3	1,214.0	20.0	0.0	8.5	40.0	0.0	0.0	0.0	0.0	0.0	0.0	1,847.8
Total Projects	New Generation	1,770.9	9,813.3	2,295.2	1,137.0	54.4	3,027.3	1,642.9	574.4	11.7	18,381.0	3,017.1	514.9	1,780.2	657.0	72.7	368.6	252.1	328.7	730.9	40.0	46,470.1
	Upgrade	10.0	463.0	75.0	20.0	0.0	20.0	20.0	85.0	8.3	1,591.8	20.0	0.0	48.6	40.0	0.0	0.0	0.0	0.0	1.3	0.0	2,403.0

Relationship Between Project Developer and Transmission Owner

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."[32] 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. The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest.

Table 12-35 shows the relationship between the project developer and Transmission Owner for all project MW that have entered the PJM generation queue from January 1, 1997, through September 30, 2018, by transmission owner and unit type. A project where the developer is affiliated with the Transmission Owner is classified as related. A project where the developer is not affiliated with the Transmission Owner is classified as unrelated. For example, 36.0 MW of combined cycle generation projects that have entered the PJM generation queue in DEOK were projects developed by Duke Energy or subsidiaries of Duke Energy, the Transmission Owner for DEOK. These project MW are classified as related. There have been 667.5 MW of combined cycle projects that have entered the PJM generation queue in DEOK by developers not affiliated with Duke Energy. These project MW are classified as "unrelated." Of the 504,007.2 MW that have entered the queue during the time period of January 1, 1997, through September 30, 2018, 62,259.9 MW (12.4 percent) have been submitted by Transmission Owners building in their own service territory.

32 See OATT § 1 (Transmission Owner).

Table 12-35 Relationship between project developer and Transmission Owner for all interconnection queue projects MW by unit type: September 30, 2018

				MW by Unit Type																		
Parent Company	Transmission Owner	Related to Developer	Number of Projects	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
AEP	AEP	Related	47	16.0	680.0	0.0	0.0	0.0	0.0	34.0	0.0	214.0	0.0	0.0	0.0	142.7	3,918.0	90.0	0.0	0.0	0.0	5,094.7
		Unrelated	458	356.0	22,558.5	675.0	7.5	127.3	0.0	0.0	448.4	0.0	12.0	0.0	75.4	10,133.6	10,368.0	0.0	0.0	492.0	27,728.8	72,982.4
AES	DAY	Related	13	20.0	0.0	38.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.5	1,347.5	0.0	0.0	0.0	0.0	1,427.0
		Unrelated	49	39.9	1,150.0	22.0	0.0	1.9	0.0	0.0	0.0	0.0	0.0	0.0	10.0	1,641.4	0.0	0.0	0.0	0.0	2,128.0	4,993.2
DLCO	DLCO	Related	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
		Unrelated	22	20.0	665.0	205.0	40.0	19.2	0.0	0.0	106.0	1,879.0	0.0	0.0	0.0	20.0	2,810.0	0.0	0.0	0.0	0.0	5,764.2
Dominion	Dominion	Related	93	0.0	12,334.0	914.2	100.0	0.0	0.0	340.0	5.5	1,944.0	0.0	0.0	60.0	901.6	301.0	0.0	0.0	4.0	146.0	17,050.3
		Unrelated	426	115.0	9,044.5	1,236.7	0.5	227.3	0.0	0.0	29.5	0.0	0.0	10.0	119.4	19,071.2	20.0	0.0	0.0	316.3	5,747.8	35,938.2
Duke	DEOK	Related	7	23.8	36.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4	0.0	0.0	0.0	0.0	0.0	66.2
		Unrelated	25	16.0	667.5	0.0	0.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	653.0	120.0	0.0	0.0	0.0	0.0	1,573.3
EKPC	EKPC	Related	2	0.0	821.8	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	821.8
		Unrelated	11	0.0	170.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	514.9	0.0	0.0	0.0	0.0	150.3	908.2
Exelon	AECO	Related	5	0.0	730.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.3	0.0	0.0	0.0	0.0	0.0	738.3
		Unrelated	278	71.0	8,913.4	807.4	380.0	20.7	2.8	0.0	0.0	0.0	2.0	5.0	10.3	1,772.6	15.0	5.5	0.0	10.0	4,252.9	16,268.6
	BGE	Related	14	20.0	376.0	10.0	0.0	0.0	0.0	0.0	0.0	108.5	0.0	0.0	8.5	20.0	10.0	101.0	0.0	0.0	0.0	654.0
		Unrelated	56	40.6	3,012.1	157.6	18.0	133.0	0.0	0.0	0.4	3,280.0	1.3	0.0	0.0	34.4	0.0	2.5	0.0	25.0	0.0	6,704.9
	ComEd	Related	16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,185.0	0.0	0.0	0.0	9.0	0.0	0.0	0.0	0.0	0.0	1,194.0
		Unrelated	319	406.7	14,233.8	1,505.0	42.0	65.2	0.0	0.0	22.7	0.0	35.0	0.0	67.7	3,038.3	1,926.0	91.0	0.0	90.0	31,840.5	53,363.9
	DPL	Related	7	0.0	1,365.0	351.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.4	0.0	0.0	0.0	0.0	0.0	1,723.4
		Unrelated	277	122.0	5,611.6	1,461.0	600.9	42.6	0.0	0.0	0.0	0.0	0.0	0.0	84.6	3,029.7	653.0	15.0	0.0	65.0	3,064.6	14,750.0
	PECO	Related	33	40.0	6,965.0	5.0	89.5	0.0	0.0	0.0	265.0	437.8	0.0	0.0	0.0	0.0	7.0	0.0	0.0	0.0	0.0	7,809.3
		Unrelated	78	5.3	20,355.5	567.5	2.0	15.0	0.0	0.0	0.0	0.0	0.0	17.0	3.7	72.7	0.0	0.0	0.0	0.0	0.0	21,038.7
	Pepco	Related	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
		Unrelated	82	20.0	23,325.9	37.0	30.0	9.0	0.0	0.0	0.0	1,640.0	32.0	0.0	3.5	252.1	0.0	0.0	0.0	0.0	0.0	25,349.5
First Energy	APS	Related	4	0.0	1,453.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,710.0	0.0	0.0	0.0	0.0	3,163.0
		Unrelated	344	330.9	23,628.8	1,483.7	0.0	84.4	0.0	0.0	623.3	0.0	140.0	53.8	25.4	2,370.2	4,092.0	0.0	0.0	184.4	5,340.5	38,357.4
	ATSI	Related	6	0.0	1,678.0	0.0	0.0	0.0	0.0	0.0	0.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,694.0
		Unrelated	71	56.1	10,699.0	135.0	5.0	166.4	0.0	0.0	0.0	0.0	59.7	0.0	6.9	1,157.0	0.0	16.5	0.0	0.0	2,111.7	14,413.3
	JCPL	Related	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	12.0	0.0	0.0	0.0	0.0	0.0	32.0
		Unrelated	340	334.2	15,186.4	722.1	0.0	4.8	0.8	0.0	1.6	0.0	0.6	0.0	12.8	1,816.7	0.0	0.0	0.0	30.0	2,640.0	20,750.0
	Met-Ed	Related	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
		Unrelated	86	23.0	17,458.9	34.1	1,196.0	52.1	0.0	0.0	0.0	79.0	0.0	8.0	15.2	697.0	0.0	0.0	0.0	24.0	0.0	19,587.3
	PENELEC	Related	4	0.0	534.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,860.0	0.0	0.0	0.0	0.0	2,399.0
		Unrelated	246	97.4	18,727.9	1,416.7	0.9	214.4	0.0	16.0	46.3	14.0	341.8	8.0	22.8	368.6	561.0	590.0	0.0	585.0	6,812.0	29,822.6
PPL	PPL	Related	21	0.0	2,294.0	0.0	0.0	0.0	0.0	0.0	109.0	1,600.0	0.0	0.0	0.0	0.0	111.0	0.0	0.0	0.0	0.0	4,114.0
		Unrelated	226	520.0	23,176.5	423.1	8.0	234.5	0.0	1,000.0	142.6	388.0	19.9	2.4	44.7	328.7	6,896.6	0.0	0.0	31.0	3,829.9	37,045.9
PSEG	PSEG	Related	106	0.0	11,836.1	1,818.1	0.0	0.0	0.0	0.0	0.0	381.0	0.0	0.0	0.0	175.8	24.0	44.0	0.0	0.0	0.0	14,279.0
		Unrelated	192	14.5	19,315.4	462.9	608.0	62.5	4.9	0.0	1,000.0	0.0	10.6	0.0	13.7	556.4	0.0	20.0	0.0	0.0	20.0	22,088.9
Con Ed	RECO	Related	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
		Unrelated	3	0.0	6.9	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	0.0	46.9
Total		Related	380	119.8	41,102.9	3,141.3	189.5	0.0	0.0	374.0	399.5	5,886.3	0.0	0.0	68.5	1,304.6	9,288.5	235.0	0.0	4.0	146.0	62,259.9
		Unrelated	3589	2,588.6	237,907.4	11,424.8	2,938.8	1,480.3	8.5	1,016.0	2,532.8	7,280.0	654.9	104.2	520.9	47,568.4	27,461.6	740.5	0.0	1,852.7	95,666.9	441,747.3

Combined Cycle Project Developer and Transmission Owner Relationships

Table 12-36 shows the relationship between the project developer and Transmission Owner for all combined cycle project MW that have entered the PJM generation queue from January 1, 1997 through September 30, 2018, by transmission owner and project status. Of the 39,398.4 combined cycle project MW that have achieved in service or under construction status during this time period, 9,375.0 MW (23.8 percent) have been developed by Transmission Owners building in their own service territory.

Table 12-36 Relationship between project developer and transmission owner for all combined cycle project MW in PJM interconnection queue: September 30, 2018

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	100.0	580.0	0.0	0.0	0.0	680.0
		Unrelated	6,337.0	2,682.0	0.0	1,579.0	11,960.5	22,558.5
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,150.0	0.0	0.0	0.0	0.0	1,150.0
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	665.0	665.0
Dominion	Dominion	Related	25.0	3,152.0	1,681.0	0.0	7,476.0	12,334.0
		Unrelated	3,860.1	1,934.1	0.0	0.0	3,250.3	9,044.5
Duke	DEOK	Related	0.0	0.0	0.0	0.0	36.0	36.0
		Unrelated	0.0	533.0	0.0	0.0	134.5	667.5
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	821.8	821.8
		Unrelated	0.0	0.0	0.0	0.0	170.0	170.0
Exelon	AECO	Related	0.0	0.0	0.0	0.0	730.0	730.0
		Unrelated	1,061.6	870.0	452.0	235.0	6,294.8	8,913.4
	BGE	Related	0.0	256.0	0.0	0.0	120.0	376.0
		Unrelated	0.0	10.0	0.0	0.0	3,002.1	3,012.1
	ComEd	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	6,994.2	1,221.0	12.6	0.0	6,006.0	14,233.8
	DPL	Related	0.0	60.0	0.0	0.0	1,305.0	1,365.0
		Unrelated	0.0	361.2	0.0	451.0	4,799.4	5,611.6
	PECO	Related	0.0	0.0	0.0	0.0	6,965.0	6,965.0
		Unrelated	67.0	2,758.5	915.0	0.0	16,615.0	20,355.5
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	75.0	1,629.6	84.0	1,038.1	20,499.2	23,325.9
First Energy	APS	Related	0.0	525.0	0.0	0.0	928.0	1,453.0
		Unrelated	2,380.7	670.0	930.0	3,015.0	16,633.1	23,628.8
	ATSI	Related	0.0	0.0	0.0	0.0	1,678.0	1,678.0
		Unrelated	4,085.0	1,604.0	301.0	0.0	4,709.0	10,699.0
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	605.0	1,775.8	0.0	0.0	12,805.6	15,186.4
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	113.9	2,117.0	485.0	0.0	14,743.0	17,458.9
	PENELEC	Related	0.0	0.0	0.0	0.0	534.0	534.0
		Unrelated	85.0	942.3	1,100.0	163.0	16,437.6	18,727.9
PPL	PPL	Related	0.0	633.0	0.0	0.0	1,661.0	2,294.0
		Unrelated	1,722.8	4,346.0	1,483.0	0.0	15,624.7	23,176.5
PSEG	PSEG	Related	51.1	1,920.0	568.0	0.0	9,297.0	11,836.1
		Unrelated	3,091.4	806.4	0.0	0.0	15,417.6	19,315.4
Con Ed	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	6.9	6.9
Total		Related	176.1	7,126.0	2,249.0	0.0	31,551.8	41,102.9
		Unrelated	31,628.7	24,260.8	5,762.6	6,481.1	169,774.1	237,907.4

Combustion Turbine – Natural Gas Project Developer and Transmission Owner Relationships

Table 12-37 shows the relationship between the project developer and Transmission Owner for all CT – natural gas project MW that have entered the PJM generation queue from January 1, 1997 through September 30, 2018, by transmission owner and project status. Of the 9,364.0 CT – natural gas project MW that have achieved in service or under construction status during this time period, 2,107.0 (22.5 percent) have been developed by Transmission Owners building in their own service territory.

Table 12-37 Relationship between project developer and transmission owner for all CT – natural gas project MW in PJM interconnection queue: September 30, 2018

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	413.0	190.0	0.0	0.0	72.0	675.0
AES	DAY	Related	0.0	38.0	0.0	0.0	0.0	38.0
		Unrelated	0.0	22.0	0.0	0.0	0.0	22.0
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	205.0	0.0	0.0	205.0
Dominion	Dominion	Related	128.2	786.0	0.0	0.0	0.0	914.2
		Unrelated	66.0	1,116.7	0.0	0.0	54.0	1,236.7
Duke	DEOK	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	73.0	0.0	0.0	0.0	0.0	73.0
Exelon	AECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	388.0	404.4	0.0	0.0	15.0	807.4
	BGE	Related	0.0	10.0	0.0	0.0	0.0	10.0
		Unrelated	144.6	13.0	0.0	0.0	0.0	157.6
	ComEd	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,238.0	257.0	0.0	0.0	10.0	1,505.0
	DPL	Related	0.0	351.0	0.0	0.0	0.0	351.0
		Unrelated	0.0	1,461.0	0.0	0.0	0.0	1,461.0
	PECO	Related	0.0	5.0	0.0	0.0	0.0	5.0
		Unrelated	0.0	567.0	0.0	0.0	0.5	567.5
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	37.0	0.0	0.0	0.0	37.0
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	120.0	1,363.7	0.0	0.0	0.0	1,483.7
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	70.0	40.0	0.0	0.0	25.0	135.0
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	522.1	0.0	200.0	0.0	722.1
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	34.1	0.0	0.0	0.0	34.1
	PENELEC	Related	0.0	5.0	0.0	0.0	0.0	5.0
		Unrelated	463.0	391.9	0.0	68.8	493.0	1,416.7
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	403.2	0.0	0.0	19.9	423.1
PSEG	PSEG	Related	0.0	912.0	0.0	0.0	906.1	1,818.1
		Unrelated	0.0	228.9	0.0	0.0	234.0	462.9
Con Ed	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Total		Related	128.2	2,107.0	0.0	0.0	906.1	3,141.3
		Unrelated	2,975.6	7,052.0	205.0	268.8	923.4	11,424.8

Wind Project Developer and Transmission Owner Relationships

Table 12-38 shows the relationship between the project developer and Transmission Owner for all wind project MW that have entered the PJM generation queue from January 1, 1997 through September 30, 2018, by transmission owner and project status. Of the 10,035.5 wind project MW that have achieved in service or under construction status during this time period, 12.0 MW (0.1 percent) have been developed by Transmission Owners building in their own service territory.

Table 12-38 Relationship between project developer and transmission owner for all wind project MW in PJM interconnection queue: September 30, 2018

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	5,689.3	2,538.7	450.0	380.0	18,670.8	27,728.8
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	100.0	0.0	0.0	0.0	2,028.0	2,128.0
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Dominion	Dominion	Related	0.0	0.0	12.0	0.0	134.0	146.0
		Unrelated	2,400.3	0.0	734.8	76.6	2,536.1	5,747.8
Duke	DEOK	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	150.3	150.3
Exelon	AECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	619.0	7.5	0.0	0.0	3,626.4	4,252.9
	BGE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
	ComEd	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	5,671.2	2,413.5	1,228.5	0.0	22,527.3	31,840.5
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	247.8	0.0	0.0	0.0	2,816.8	3,064.6
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	444.4	1,004.0	348.6	391.4	3,152.1	5,340.5
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	816.1	0.0	0.0	0.0	1,295.6	2,111.7
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,640.0	0.0	0.0	0.0	0.0	2,640.0
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	120.3	1,001.4	70.0	100.0	5,520.3	6,812.0
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	531.1	226.5	0.0	0.0	3,072.3	3,829.9
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	20.0	20.0
Con Ed	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Total		Related	0.0	0.0	12.0	0.0	134.0	146.0
		Unrelated	19,279.4	7,191.6	2,831.9	948.0	65,416.0	95,666.9

Solar Project Developer and Transmission Owner Relationships

Table 12-39 shows the relationship between the project developer and Transmission Owner for all solar project MW that have entered the PJM generation queue from January 1, 1997 through September 30, 2018, by transmission owner and project status. Of the 1,807.4 solar project MW that have achieved in service or under construction status during this time period, 440.6 MW (24.4 percent) have been developed by Transmission Owners building in their own service territory.

Table 12-39 Relationship between project developer and transmission owner for all solar project MW in PJM interconnection queue: September 30, 2018

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	68.0	14.7	0.0	10.0	50.0	142.7
		Unrelated	6,786.0	0.0	20.0	10.0	3,317.6	10,133.6
AES	DAY	Related	0.0	0.0	0.0	0.0	21.5	21.5
		Unrelated	1,116.5	2.5	0.0	20.0	502.4	1,641.4
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	20.0	0.0	0.0	0.0	0.0	20.0
Dominion	Dominion	Related	375.3	294.4	0.0	0.0	231.9	901.6
		Unrelated	10,485.9	254.9	309.7	44.6	7,976.1	19,071.2
Duke	DEOK	Related	0.0	0.0	0.0	0.0	6.4	6.4
		Unrelated	380.0	0.0	0.0	0.0	273.0	653.0
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	325.0	0.0	0.0	0.0	189.9	514.9
Exelon	AECO	Related	0.0	0.0	0.0	0.0	8.3	8.3
		Unrelated	48.3	57.3	0.0	0.0	1,667.0	1,772.6
	BGE	Related	0.0	0.0	0.0	0.0	20.0	20.0
		Unrelated	0.0	1.1	0.0	0.0	33.3	34.4
	ComEd	Related	0.0	9.0	0.0	0.0	0.0	9.0
		Unrelated	1,679.5	0.0	0.0	0.0	1,358.8	3,038.3
	DPL	Related	0.0	7.4	0.0	0.0	0.0	7.4
		Unrelated	1,365.0	111.0	37.0	0.0	1,516.7	3,029.7
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	18.0	3.3	0.0	0.0	51.4	72.7
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	76.3	0.0	0.0	0.0	175.8	252.1
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	507.5	53.0	10.0	313.3	1,486.4	2,370.2
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	940.9	0.0	0.0	0.0	216.1	1,157.0
	JCPL	Related	0.0	0.0	0.0	0.0	12.0	12.0
		Unrelated	35.1	301.6	81.9	37.6	1,360.6	1,816.7
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	230.0	0.0	0.0	0.0	467.0	697.0
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	243.9	0.0	0.0	3.0	121.7	368.6
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	30.0	15.0	0.0	0.0	283.7	328.7
PSEG	PSEG	Related	24.3	111.1	4.0	0.0	36.4	175.8
		Unrelated	25.0	82.4	26.1	6.0	416.9	556.4
Con Ed	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	40.0	0.0	0.0	0.0	0.0	40.0
Total		Related	467.6	436.6	4.0	10.0	386.5	1,304.6
		Unrelated	24,352.7	882.1	484.7	434.5	21,414.4	47,568.4

Regional Transmission Expansion Plan (RTEP)[33]

The PJM RTEP process is designed to identify needed transmission system additions and improvements to continue to provide reliable service throughout the RTO. The objective of the RTEP process is to provide PJM with an optimal set of solutions necessary to solve reliability issues, operational performance issues and transmission constraints. Additionally, board approved transmission system enhancements to meet local reliability requirements are also included in the RTEP process.

The RTEP process initially considered only factors such as load growth and the generation interconnection requests in its development of the 15 year plan. Today, the RTEP process includes a broader range of inputs. Some of those inputs include the effects of public policy, market efficiency, interregional coordination and the effects of aging infrastructure.

RTEP Process

The PJM RTEP process is a 24 month planning process that identifies reliability issues for the next 15 year period. This 24 month planning process includes a process to build power flow models that represent the expected future system topology, studies to identify issues, stakeholder input and PJM Board of Manager approvals. The 24 month planning process is made up of overlapping 18 month planning cycles to identify and develop shorter lead time transmission upgrades and one 24 month planning cycle to provide sufficient time for the identification and development of longer lead time transmission upgrades that may be required to satisfy planning criteria.

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.[34]

Market Efficiency Process

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 based on production cost analyses.[35] PJM presents the RTEP market efficiency enhancements to the PJM Board, along with stakeholder input, for Board approval.

To be 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 to the present value of the total annual cost for 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 projects for years five through 15. This long-term proposal window takes place concurrent with the long-term proposal window for reliability projects.[36]

The first market efficiency cycle conducted under Order 1000 was performed during the 2014/2015 RTEP long term window. Issues were identified on a

33 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. 42 (August 23, 2018) <http://www.pjm.com/-/media/documents/manuals/m14b.ashx?la=en>.

34 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>.

35 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>.

36 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>.

total of 77 flowgates, 57 of which were market efficiency drivers. The proposal window was open from October 30, 2014, through February 27, 2015. PJM received 119 proposals, 93 of which addressed the market efficiency issues. A total of 14 projects were approved by the PJM Board for this window, 13 of which were market efficiency projects.

The second market efficiency cycle was performed during the 2016/2017 RTEP long term window. Issues were identified on a total of four flowgates, all four of which were market efficiency drivers, needed to address historical congestion. The proposal window was open from November 1, 2016 through February 28, 2017. PJM received 96 proposals, all 96 of which addressed the market efficiency issues. A total of four projects were approved by the PJM Board for this window, four of which were market efficiency projects.

The third market efficiency cycle is currently being prepared for the 2018/2019 RTEP long term window. The proposal window will be open from November 1, 2018 through February 28, 2019.

During the first nine months of 2018, the PJM Board of Managers received correspondence from several officials, representing regions in Pennsylvania and Maryland, requesting an updated benefit/cost evaluation and the cancellation of the previously approved Transource AP-South market efficiency project.[37] [38] [39] [40] Approved market efficiency projects periodically undergo a reevaluation process to ensure that the benefit/cost ratio continues to meet the 1.25:1 threshold. The Transource AP-South project was reevaluated in September 2017, February 2018 and again in September 2018. The project exceeded the 1.25:1 threshold in all reevaluations. PJM also concluded that there would be significant reliability violations with the project removed from the model.[41]

37 See Letter from Governor Larry Hogan, State of Maryland, Office of the Governor.(July 10, 2018)) <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180828-gov-hogan-transource-july-2018-letter-to-pjm-board.ashx?la=en>.

38 See Letter from State Representative Kristin Phillips Hill, 93rd District, Pennsylvania House of Representatives (September 6, 2018) <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180906-pa-rep-phillips-hill-letter-re-transource-llc.ashx?la=en>.

39 See Letter from State Representative Stanley E. Saylor, 94th District, Pennsylvania House of Representatives (August 1, 2018) <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180907-pa-rep-saylor-letter-re-transource-llc.ashx?la=en>.

40 See Letter from Paula M. Carmody, People Counsel, State of Maryland Office of People's Counsel (September 6, 2018) <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180907-opc-letter-to-pjm-board-re-sept-2018-transource-retool.ashx?la=en>.

41 See "Transource AP-South (2014/15_9A) Project Reevaluation," <https://www.pjm.com/-/media/committees-groups/committees/teac/20180913/20180913-ap-south-9a-project-reevaluation-sept-2018.ashx>.

The Benefit/Cost Evaluation

For an RTEP project to be recommended to the PJM Board of Managers for approval as a Market Efficiency project, 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 total benefit of a project is calculated as the sum of the present value of calculated Energy Market Benefits and calculated Reliability Pricing Model (RPM) Benefits for the 15 year period. The net present value of the benefits of the project are calculated for 15 years, starting with the projected in service date. Reductions in costs are calculated as a positive benefit. The method for calculating Energy Market Benefits and Reliability Pricing Model Benefits used to measure the benefit of an RTEP project for purposes of the 1.25:1 benefit/cost ratio threshold depends on whether the project is regional or subregional. A regional project is any project rated at or above 230 kV. A subregional project is any project rated at less than 230 kv.

The Energy Market Benefit analysis is generated using an energy market simulation tool that produces an hourly least-cost, security constrained market solution, complete with total operational costs, hourly LMPs, bus specific injections and bus specific withdrawals for each modeled year with and without the proposed RTEP project. Using the output from the model, PJM calculates changes in Energy Production Costs and Load Energy Payments. Changes in Energy Production Costs are calculated on a system wide basis. Using the modeled changes in LMPs, changes in Load Energy Payments are calculated on a zonal basis and are netted against corresponding changes in the value of any Auction Revenue Rights (ARR) that sink in that zone. The value of the ARR rights with and without the RTEP project is evaluated based on changes in CLMPs on the latest, historic allocation of ARR rights. ARR MW allocations are not adjusted to reflect any potential changes in ARR allocations which may be allowed by the RTEP upgrade. To generate the estimate of the Energy Market Benefits, PJM simulates four year (RTEP -4, RTEP, RTEP +3 and RTEP +6) and interpolates between the simulated years and extrapolates after the RTEP +6 simulation.

For a regional project, the Energy Market Benefit for each modeled year is equal to 50 percent of the change in system-wide Total Energy Production Costs with and without the project plus 50 percent of the change in zonal Load Energy Payments with and without the project, including only those zones where the project reduced the Load Energy Payments. For subregional projects, the Energy Market Benefits for each modeled year is equal to the change in zonal Load Energy Payments with and without the project, including only those zones where the project reduced the Load Energy Payments.

The Reliability Pricing Model Benefit analysis is conducted using the Reliability Pricing Model solution software, with and without the proposed RTEP project, using a set of estimated capacity offers. To generate the estimate of the Energy Market Benefits, PJM simulates three years (RTEP, RTEP +3 and RTEP +6) and interpolates between the simulated years and extrapolates after the RTEP +6 simulation.

For a regional project, the Reliability Pricing Model Benefit for each modeled year is equal to 50 percent of the change in system-wide Total System Capacity Cost with and without the project plus 50 percent of the change in zonal Load Capacity Payments with and without the project, including only those zones where the project reduced the Load Capacity Payments. For subregional projects, the Reliability Pricing Model Benefits for each modeled year is equal to the change in zonal Load Capacity Payments with and without the project, including only those zones where the project reduced the Load Capacity Payments.

The difference in the benefits calculation used in the regional and subregional cost benefit threshold tests are related to how costs are allocated for approved regional and subregional projects. The costs of an approved regional project are allocated so that 50 percent of the total costs are allocated on a system wide load ratio share basis and the remaining 50 percent of the total costs are allocated to zones with projected Energy Market Benefits and Reliability Pricing Model Benefits in proportion to those projected positive benefits. The costs of an approved subregional project are allocated so that the total costs of the project is allocated to zones with projected Energy Market benefits and Reliability Pricing Model Benefits in proportion to those projected positive benefits.

The MMU recommends that PJM reevaluate the rules governing cost benefit analysis and cost allocation for economic projects. The current benefit analysis for a regional project, for example, explicitly ignores the negative effects that an RTEP project may have on a subset of zones when calculating the Energy Market Benefits, yet allocates 50 percent of the total cost of a project to the entire system, including that zone hurt by the RTEP project. It is not clear that the evaluation of Energy Production Costs benefits as a fifty percent contributor of benefit justifies allocating fifty percent of the costs on a system-wide basis, as the production cost saving are likely realized within the same zones that receive the Energy Market Benefits. More specific analysis of locational costs and benefits should be included in the overall evaluation.

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).[42]

The allocation of costs to each RTO for TMEPs will be in proportion to the benefits received.[43]

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.[44] [45]

The first TMEP analysis occurred in 2017 and 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,

42 See *PJM Interconnection, L.L.C,* Docket No. ER17-718-000 (December 30, 2016).
43 See *PJM Interconnection, L.L.C,* Docket No. ER17-729-000 (December 30, 2016).
44 See *PJM Interconnection, L.L.C,* Docket No. ER17-718-000, ER17-721-000 and ER17-729-000 (Not Consolidated) (November 2, 2017).
45 161 FERC ¶ 61,005.

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.[46]

The 2018 TMEP analysis included the investigation of congestion on 61 market to market flowgates. The study resulted in the evaluation of 19 potential upgrades, resulting in the recommendation of two TMEP projects. The two projects address $25 million in historical congestion, with a TMEP benefit of $31.9 million. The projects have a total cost of $4.5 million, with a 7.1 average benefit/cost ratio. PJM and MISO will present the two recommended projects to their boards in December 2018.[47]

Supplemental Transmission 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 inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[48] 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 are currently excluded from the Order No. 1000 competitive process.

Figure 12-3 shows the latest cost estimate of all supplemental projects by expected in service year. FERC Order 890 was issued on February 16, 2007, and implemented in PJM starting in 2008. Order 890 required Transmission Providers to participate in a coordinated, open and transparent planning process. Prior to the implementation of Order 890, there were transmission projects planned by transmission owners and included in the PJM planning models, that were not included in the totals shown in Figure 12-3, Table 12-40 and Table 12-41. There has been a significant increase in supplemental projects coincident with the coordinated, open and transparent planning process introduced by the implementation of Order 890 starting in 2008 and the competitive planning process introduced by the implementation of FERC Order No. 1000 starting in 2011.

46 See PJM. "*MISO PJM IPSAC*," (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.
47 See PJM. "*MISO PJM IPSAC*," (October 5, 2018) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20181005/20181005-ipsac-presentation.ashx>.
48 See PJM. "*Transmission Construction Status*," (January 23, 2018) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

Figure 12-3 Latest cost estimate of supplemental projects by expected in service year: 1998 through 2018

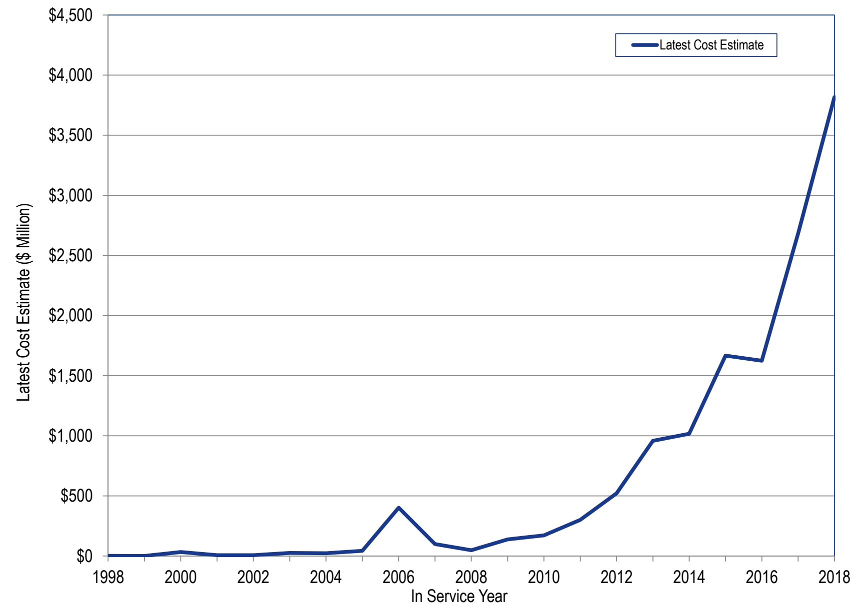


Table 12-40 shows the number of supplemental projects by expected in service year for each transmission zone. The average number of supplemental projects in each expected in service year increased by 500.0 percent, from 20 for years 1998 through 2007 (pre Order 890) to 120 for years 2008 through 2018 (post Order 890).

Table 12-40 Number of supplemental projects by expected in service year and zone: 1998 through 2030

Year	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	Total
1998	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	3
1999	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	2
2000	0	0	0	0	0	0	0	0	0	0	11	0	0	0	0	0	0	0	0	11
2001	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	14
2002	0	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	0	0	10
2003	3	0	0	0	0	0	0	0	0	0	10	0	0	0	0	2	0	0	0	15
2004	5	0	10	0	0	9	0	0	0	0	12	0	2	0	0	0	0	0	2	40
2005	4	2	8	0	0	4	0	0	0	1	14	0	1	0	1	2	0	0	2	39
2006	4	2	5	0	0	6	0	0	0	0	9	0	1	0	0	1	0	1	1	30
2007	1	1	5	0	4	5	0	0	4	0	6	0	0	0	0	2	0	1	6	35
2008	3	0	15	0	1	6	0	0	1	7	3	0	0	1	0	0	0	3	1	41
2009	3	1	5	0	1	8	0	0	3	3	5	0	0	0	5	1	0	0	2	37
2010	0	6	7	0	3	4	0	0	6	3	0	0	1	2	2	0	0	2	5	41
2011	0	8	8	0	0	2	0	0	5	2	0	0	1	0	4	0	0	3	4	37
2012	0	5	6	4	1	2	0	7	3	16	1	0	2	0	1	0	0	4	11	63
2013	5	21	4	5	0	11	0	6	5	13	1	0	1	1	1	0	1	13	19	107
2014	2	31	2	8	2	14	0	5	6	18	3	2	2	0	1	2	0	8	16	122
2015	4	15	2	9	1	37	0	8	4	17	5	4	2	0	1	0	4	7	25	145
2016	5	10	4	17	0	26	0	6	2	13	4	2	0	1	3	2	3	11	30	139
2017	6	124	7	26	1	23	0	3	8	34	7	5	0	3	0	3	2	22	38	312
2018	14	98	5	8	2	12	0	12	6	24	11	6	0	0	2	1	0	29	42	272
2019	7	43	0	1	2	5	0	4	1	10	2	7	0	0	1	0	1	40	23	147
2020	8	21	1	0	0	1	0	1	0	12	2	3	0	0	0	1	0	20	26	96
2021	3	27	0	0	0	1	10	0	2	7	0	2	1	0	0	0	0	23	7	83
2022	2	0	0	0	1	0	0	0	0	0	5	0	1	0	0	0	2	18	0	29
2023	1	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	8	0	11
2024	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	0	8
2025	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	3	0	5
2026	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	11	0	11
2027	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1
Total	83	415	94	78	20	176	10	52	56	181	141	31	16	8	22	17	13	234	260	1,907

Table 12-41 shows the latest cost estimate of supplemental projects by expected in service year for each transmission zone. The average latest cost of supplemental projects in each expected in service year increased by 1,724.7 percent, from $64.5 million for years 1998 through 2007 (pre Order 890) to $1,176.9 million for years 2008 through 2018 (post Order 890).

Table 12-41 Latest cost estimate by expected in service year and zone ($ millions): 1998 through 2030

Year	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	PECO	PENELEC	Pepco	PPL	PSEG	Total
1998	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67
1999	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.78	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.78
2000	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.95	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.95
2001	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79
2002	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.00
2003	$7.42	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.75	$0.00	$0.00	$0.00	$0.00	$9.60	$0.00	$0.00	$0.00	$25.77
2004	$4.44	$0.00	$9.99	$0.00	$0.00	$0.82	$0.00	$0.00	$0.00	$0.00	$7.32	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22.58
2005	$4.06	$14.67	$10.11	$0.00	$0.00	$2.58	$0.00	$0.00	$0.00	$0.02	$10.97	$0.00	$0.00	$0.00	$0.50	$0.00	$0.00	$0.00	$0.00	$42.90
2006	$4.03	$309.70	$0.94	$0.00	$0.00	$48.93	$0.00	$0.00	$0.00	$0.00	$11.63	$0.00	$6.00	$0.00	$0.00	$1.50	$0.00	$0.33	$18.80	$401.85
2007	$0.56	$2.06	$9.85	$0.00	$37.61	$4.65	$0.00	$0.00	$31.75	$0.00	$9.71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.34	$2.25	$98.77
2008	$2.36	$0.00	$12.03	$0.00	$0.45	$7.61	$0.00	$0.00	$7.00	$14.01	$2.28	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.60	$0.00	$47.33
2009	$0.77	$0.90	$12.17	$0.00	$5.00	$21.11	$0.00	$0.00	$19.60	$2.12	$7.36	$0.00	$0.00	$0.00	$48.10	$2.73	$0.00	$0.00	$17.60	$137.46
2010	$0.00	$34.36	$12.13	$0.00	$18.90	$1.38	$0.00	$0.00	$34.45	$14.98	$0.00	$0.00	$0.03	$4.58	$31.80	$0.00	$0.00	$1.08	$17.72	$171.41
2011	$0.00	$37.60	$9.30	$0.00	$0.00	$1.00	$0.00	$0.00	$16.72	$85.67	$0.00	$0.00	$1.16	$0.00	$113.30	$0.00	$0.00	$0.78	$34.60	$300.13
2012	$0.00	$46.00	$5.12	$0.35	$2.20	$12.60	$0.00	$26.06	$11.60	$165.74	$0.99	$0.00	$6.61	$0.00	$12.60	$0.00	$0.00	$8.91	$223.01	$521.79
2013	$3.15	$134.93	$1.10	$33.68	$0.00	$59.25	$0.00	$9.93	$81.98	$25.03	$0.99	$0.00	$0.05	$4.10	$22.50	$0.00	$2.40	$75.84	$503.72	$958.65
2014	$8.03	$387.00	$5.97	$58.70	$21.20	$60.37	$0.00	$2.43	$14.90	$88.61	$5.96	$0.38	$5.60	$0.00	$13.30	$1.30	$0.00	$33.18	$309.70	$1,016.63
2015	$3.73	$237.45	$3.80	$21.90	$2.00	$376.00	$0.00	$14.12	$4.53	$113.53	$13.06	$1.56	$0.30	$0.00	$33.80	$0.00	$42.50	$50.17	$748.01	$1,666.46
2016	$73.54	$31.68	$18.40	$182.70	$0.00	$308.15	$0.00	$15.13	$26.95	$40.68	$26.60	$0.25	$0.00	$2.37	$86.40	$0.40	$7.80	$58.76	$744.18	$1,623.99
2017	$39.48	$693.49	$14.30	$149.80	$0.09	$154.65	$0.00	$64.47	$3.62	$106.99	$74.96	$2.35	$0.00	$14.70	$0.00	$8.30	$168.00	$246.81	$942.24	$2,684.25
2018	$99.94	$601.79	$10.10	$14.50	$4.19	$136.20	$0.00	$36.20	$26.38	$176.67	$101.25	$14.90	$0.00	$0.00	$47.60	$0.80	$0.00	$400.20	$2,146.14	$3,816.86
2019	$75.98	$453.28	$0.00	$32.00	$69.20	$15.80	$0.00	$18.84	$10.60	$77.60	$12.45	$29.54	$0.00	$0.00	$0.80	$0.00	$73.50	$703.31	$797.00	$2,369.90
2020	$106.17	$459.86	$3.60	$0.00	$0.00	$28.00	$0.00	$0.66	$0.00	$24.63	$29.30	$15.46	$0.00	$0.00	$0.00	$12.80	$0.00	$264.82	$752.20	$1,697.50
2021	$4.63	$454.75	$0.00	$0.00	$0.00	$0.00	$57.10	$0.00	$40.00	$45.15	$0.00	$14.70	$6.90	$0.00	$0.00	$0.00	$0.00	$376.68	$229.00	$1,228.91
2022	$26.80	$0.00	$0.00	$0.00	$203.00	$0.00	$0.00	$0.00	$0.00	$0.00	$47.98	$0.00	$22.00	$0.00	$0.00	$0.00	$416.00	$304.62	$0.00	$1,020.40
2023	$2.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$13.80	$0.00	$8.50	$0.00	$0.00	$0.00	$0.00	$97.60	$0.00	$122.30
2024	$2.80	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$199.70	$0.00	$202.50
2025	$64.00	$0.00	$0.00	$0.00	$7.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$47.00	$0.00	$118.50
2026	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$272.75	$0.00	$272.75
2027	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.70	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.70
2028	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2029	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2030	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2.01	$0.00	$2.01
Total	$534.29	$3,899.52	$138.91	$493.63	$371.34	$1,239.09	$57.10	$187.84	$330.08	$982.12	$434.52	$79.14	$57.15	$25.75	$410.70	$37.43	$710.20	$3,146.48	$7,486.17	$20,621.46

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, to ensure maximum competition, that PJM support ending the exemption of supplemental projects from the Order No. 1000 competitive process.

End of Life Transmission Projects

An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that has, or is approaching, the end of its useful life. End of life transmission projects fall under the Transmission Owner Form 715 Planning Criteria, and are currently exempt from the competitive planning process.[49] End of life transmission projects are already included in the supplemental projects totals or, if included in the transmission owners' reliability plan, will be included in the baseline project list as a reliability criteria project.

Transmission Competition

The MMU makes several recommendations related to the competitive transmission planning process evolves. These recommendations will help ensure that the process is an open and transparent process that results in the most cost effective solutions.

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.

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.

49 See PJM Operating Agreement. Schedule 6 § 1.5.8(o)

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.

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.

Competitive Planning Process Exclusions

There are several project types that are currently exempt from the competitive planning process. These projects types include:

- **Immediate Need Exclusion:** Due to the immediate need of the violation (3 years or less), the timing required for an RTEP proposal window is considered to be infeasible. As a result, the local Transmission Owner is the Designated Entity.[50]
- **Below 200kV:** Due to the lower voltage level of the identified violation(s), the driver(s) for this project are currently excluded from the competitive proposal window process. As a result, the local Transmission Owner is the Designated Entity.[51]
- **FERC 715 (TO Criteria):** Due to the violation need of this project resulting solely from FERC 715 TO Reliability Criteria, the driver(s) for this project are currently excluded from the competitive proposal window process. As a result, the local Transmission Owner is the Designated Entity.[52]
- **Substation Equipment:** Due to identification of the limiting element(s) as substation equipment, the driver(s) for this project are currently excluded from the competitive proposal window process. As a result, the local Transmission Owner is the Designated Entity.[53]

50 See PJM Operating Agreement. Schedule 6 § 1.5.8(m)
51 See PJM Operating Agreement. Schedule 6 § 1.5.8(n)
52 See PJM Operating Agreement. Schedule 6 § 1.5.8(o)
53 See PJM Operating Agreement. Schedule 6 § 1.5.8(p)

While the PJM Operating Agreement defines who will be the Designated Entity for projects that are excluded from the competitive planning process, neither the PJM Operating Agreement nor the various commission orders on transmission competition prohibit PJM from permitting competition to provide financing for such projects. 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. In addition, the criteria for and need for all exclusions from the competitive process should be reviewed. There does not appear to be any market reason to exclude transmission projects from competition.

Cost Capping

The MMU recommended that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. In 2017, PJM formed a special session of the PJM Planning Committee for consideration of cost commitments during the evaluation of competititive transmission proposals. On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM to develop a comparative framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. The initial motion required the comparative framework to be presented at the December 2018 meeting of the MRC for vote and to be effective for the 2018 long lead project proposal window. At the August 23, 2018, meeting of the MRC, the committee approved a motion to delay the comparative framework deadlines by one year.

Board Authorized 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.

An RTEP project can be approved by the PJM Board if the project ensures compliance with NERC, regional and local transmission owner planning criteria or to address market efficiency congestion relief. These projects are considered “Baseline Projects”. PJM Board approved RTEP projects that are necessary to allow new generation to interconnect reliably are considered “Network Projects”. As of December 31, 2017, the PJM Board has approved $35.1 billion in system enhancements. Of that, $27.9 billion (79.5 percent) were baseline projects and $7.2 billion (20.5 percent) were network projects.[54]

In the first nine months of 2018, $1.60 billion in additional projects were approved by the PJM Board:

- On February 13, 2018, the PJM Board of Managers authorized an additional $328.8 million in transmission upgrades and additions.
- On April 10, 2018, the PJM Board of Managers authorized an additional $639.0 million in transmission upgrades and additions.
- On July 31, 2018, the PJM Board of Managers authorized an additional $629.2 million in transmission upgrades and additions.

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.[55] 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 12-43.[56]

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

54 See PJM. "2017 Regional Transmission Expansion Plan – Book 1," P 4. <http://www.pjm.com/-/media/library/reports-notices/2017-rtep/2017-rtep-book-1.ashx?la=en>.
55 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).
56 See PJM. "Manual 3: Transmission Operations," Rev. 53 (June 1, 2018), at 65–66.

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.[57] Table 12-42 shows that 70.5 percent of the requested outages were planned for less than or equal to five days and 10.2 percent of requested outages were planned for greater than 30 days in the 2018/2019 planning period. It also shows that 75.9 percent of the requested outages were planned for less than or equal to five days and 7.7 percent of requested outages were planned for greater than 30 days in the 2017/2018 planning period.

All of the outage data in this section in the analysis except for the day-ahead market are for outages scheduled to occur in the planning periods 2017/2018 and 2018/2019, regardless of when they were initially submitted.[58] The outage data in the analysis for the day-ahead market are for outages scheduled to occur from January 1, 2015, through September 30, 2018.

Table 12-42 Transmission facility outage request summary by planned duration: 2017/2018 and 2018/2019

	2017/2018		2018/2019	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	16,206	75.9%	8,547	70.5%
>5 & <=30	3,489	16.3%	2,340	19.3%
>30	1,650	7.7%	1,236	10.2%
Total	21,345	100.0%	12,123	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 12-43.[59]

57 *Id.* at 70.
58 The hotline tickets, EMS tripping tickets or test outage tickets were excluded. The analysis includes only the transmission outage tickets submitted by PJM companies which are currently active.
59 See PJM. "Manual 3: Transmission Operations," Rev. 53 (June 1, 2018) at 65–66.

The purpose of the rules defined in Table 12-43 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.[60]

Table 12-43 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 12-44 shows a summary of requests by received status. In the 2018/2019 planning period, 37.9 percent of outage requests received were late. In the 2017/2018 planning period, 49.7 percent of outage requests received were late.

Table 12-44 Transmission facility outage request summary by received status: 2017/2018 and 2018/2019

	2017/2018				2018/2019			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	8,418	7,788	16,206	48.1%	5,389	3,158	8,547	36.9%
>5 & <=30	1,712	1,777	3,489	50.9%	1,530	810	2,340	34.6%
>30	609	1,041	1,650	63.1%	612	624	1,236	50.5%
Total	10,739	10,606	21,345	49.7%	7,531	4,592	12,123	37.9%

60 See "Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).

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.[61] Table 12-45 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the 2018/2019 planning period, 10.0 percent were for emergency outages. Of all outage requests scheduled to occur in the 2017/2018 planning period, 12.6 percent were for emergency outages.

Table 12-45 Transmission facility outage request summary by emergency: 2017/2018 and 2018/2019

	2017/2018				2018/2019			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	2,051	14,155	16,206	12.7%	860	7,687	8,547	10.1%
>5 & <=30	399	3,090	3,489	11.4%	204	2,136	2,340	8.7%
>30	248	1,402	1,650	15.0%	149	1,087	1,236	12.1%
Total	2,698	18,647	21,345	12.6%	1,213	10,910	12,123	10.0%

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."[62]

61 PJM. "Manual 3: Transmission Operations," Rev. 53 (June 1, 2018) at 81.
62 PJM added this definition to Manual 38 in February 2017. PJM. "Manual 38: Operations Planning," Rev. 11 (February 1, 2018) at 20.

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 12-46 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the 2018/2019 planning period, 8.6 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 4.9 percent (51 out of 1,041) were denied by PJM in the 2018/2019 planning period and 18.5 percent (193 out of 1,041) were cancelled (Table 12-48). 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, 3.6 percent (58 out of 1,602) were denied by PJM in the 2017/2018 planning period and 19.6 percent (314 out of 1,602) were cancelled (Table 12-48).

Table 12-46 Transmission facility outage request summary by congestion: 2017/2018 and 2018/2019

	2017/2018				2018/2019			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	1,094	15,112	16,206	6.8%	667	7,880	8,547	7.8%
>5 & <=30	357	3,132	3,489	10.2%	241	2,099	2,340	10.3%
>30	151	1,499	1,650	9.2%	133	1,103	1,236	10.8%
Total	1,602	19,743	21,345	7.5%	1,041	11,082	12,123	8.6%

Table 12-47 shows the outage requests summary by received status, congestion status and emergency status. In the 2018/2019 planning period, 27.9 percent of requests were submitted late and were nonemergency while 1.1 percent of requests (139 out of 12,123) were late, nonemergency, and expected to cause congestion. In the 2017/2018 planning period, 37.1 percent of request were submitted late and were nonemergency while 1.4 percent of requests (297 out of 21,345) were late, nonemergency, and expected to cause congestion.

Table 12-47 Transmission facility outage request summary by received status, emergency and congestion: 2017/2018 and 2018/2019

		2017/2018				2018/2019			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent of Total	Congestion Expected	No Congestion Expected	Total	Percent of Total
Late	Emergency	85	2,592	2,677	12.5%	34	1,175	1,209	10.0%
	Non Emergency	297	7,632	7,929	37.1%	139	3,244	3,383	27.9%
On Time	Emergency	3	18	21	0.1%	0	4	4	0.0%
	Non Emergency	1,217	9,501	10,718	50.2%	868	6,659	7,527	62.1%
Total		1,602	19,743	21,345	100.0%	1,041	11,082	12,123	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.[63] Table 12-48 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 12-48. Table 12-48 shows that of all the outage requests that were expected to cause congestion, 4.9 percent (51 out of 1,041) were denied by PJM in the 2018/2019 planning period, 37.3 percent were complete and 18.5 percent (193 out of 1,041) were cancelled. Of all the outage requests that were expected to cause congestion, 3.6 percent (58 out of 1,602) were denied by PJM in the 2017/2018 planning period, 70.8 percent were complete and 19.6 percent (314 out of 1,602) were cancelled.

Table 12-48 Transmission facility outage requests that might cause congestion status summary: 2017/2018 and 2018/2019

		2017/2018						2018/2019					
Received Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	11	74	0	0	85	87.1%	4	29	1	0	34	85.3%
	Non Emergency	47	220	9	18	297	74.1%	26	71	29	9	139	51.1%
On Time	Emergency	2	1	0	0	3	33.3%	0	0	0	0	0	0.0%
	Non Emergency	254	839	77	40	1,217	68.9%	163	288	365	42	868	33.2%
Total		314	1,134	86	58	1,602	70.8%	193	388	395	51	1,041	37.3%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[64] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Table 12-48 shows that in the 2017/2018 planning period, many (74.1 percent or 220 out of 297) outages that were nonemergency, expected to cause congestion, and late transmission outages were approved and completed compared to (51.1 percent or 71 out of 139) outages in the 2018/2019 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.

63 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2017).
64 OA Schedule 1 § 1.9.2.

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-49 is a summary of all the outage requests planned for the planning periods 2017/2018 and 2018/2019 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 2018/2019 planning period, 21.8 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 8.7 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2017/2018 planning period, 32.2 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 12.5 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

Table 12-49 Rescheduled and cancelled transmission outage request summary: 2017/2018 and 2018/2019

	2017/2018					2018/2019				
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	16,206	3,632	22.4%	2,366	14.6%	8,547	1,494	17.5%	948	11.1%
>5 & <=30	3,489	2,123	60.8%	229	6.6%	2,340	748	32.0%	77	3.3%
>30	1,650	1,113	67.5%	65	3.9%	1,236	402	32.5%	25	2.0%
Total	21,345	6,868	32.2%	2,660	12.5%	12,123	2,644	21.8%	1,050	8.7%

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.[65] 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.[66] 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.

65 PJM. "Manual 3: Transmission Operations," Rev. 53 June 1, 2018) at 70.
66 *Id.*

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-43) 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 12-50 shows that there were 8,237 transmission equipment planned outages in the 2018/2019 planning period, of which 1,285 were planned outages longer than 30 days, and of which 189 or 2.3 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 12-50 Transmission outage summary: 2017/2018 and 2018/2019

		2017/2018		2018/2019	
Planned Duration (Days)	Divided into Shorter Periods	Number of Outages	Percent of Total	Number of Outages	Percent of Total
> 30	No	1,440	11.3%	1,096	13.3%
	Yes	244	1.9%	189	2.3%
<= 30		11,033	86.8%	6,952	84.4%
Total		12,717	100.0%	8,237	100.0%

Table 12-51 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 2018/2019 planning period, there would have been 35 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 12-51 Summary of potentially long duration (> 30 days) outages: 2017/2018 and 2018/2019

	2017/2018		2018/2019	
Planned Duration (Days)	Number of Outages	Percent of Total	Number of Outages	Percent of Total
<=31	6	2.5%	8	4.2%
>31 & <=62	25	10.2%	35	18.5%
>62 & <=93	18	7.4%	10	5.3%
>93	195	79.9%	136	72.0%
Total	244	100.0%	189	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.[67]

67 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 2018/2019 planning period, 241 outage requests were included in the annual FTR market outage list and 11,882 outage requests were not included. In the 2017/2018 planning period, 250 outage requests were included in the annual FTR market outage list and 21,095 outage requests were not included. Table 12-52, Table 12-53, Table 12-54 and Table 12-55 show the summary information on the modeled outage requests and Table 12-56 and Table 12-57 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-52 shows that 6.2 percent of the outage requests modeled in the Annual FTR Market for the 2018/2019 planning period had a planned duration of less than two weeks and that 13.3 percent of the outage requests (32 out of 241) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 3.6 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.

Table 12-52 Annual FTR market modeled transmission facility outage requests by received status: 2017/2018 and 2018/2019

	2017/2018				2018/2019			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	7	2	9	3.6%	14	1	15	6.2%
>=2 weeks & <2 months	80	9	89	35.6%	80	5	85	35.3%
>=2 months	131	21	152	60.8%	115	26	141	58.5%
Total	218	32	250	100.0%	209	32	241	100.0%

Table 12-53 shows the annual FTR market modeled outage requests summary by emergency status and received status. Three of the annual FTR market modeled outages expected to occur in the 2018/2019 planning period were emergency outages. None of the modeled outages expected to occur in the 2017/2018 planning period were emergency outages.

Table 12-53 Annual FTR market modeled transmission facility outage requests by emergency and received status: 2017/2018 and 2018/2019

		2017/2018				2018/2019			
Received Status	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	7	7	100.0%	0	14	14	100.0%
	>=2 weeks & <2 months	0	80	80	100.0%	0	80	80	100.0%
	>=2 months	0	131	131	100.0%	0	115	115	100.0%
	Total	0	218	218	100.0%	0	209	209	100.0%
Late	<2 weeks	0	2	2	100.0%	0	1	1	100.0%
	>=2 weeks & <2 months	0	9	9	100.0%	0	5	5	100.0%
	>=2 months	0	21	21	100.0%	3	23	26	88.5%
	Total	0	32	32	100.0%	3	29	32	90.6%

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 12-54 shows a summary of requests by expected congestion and received status. Overall, 6.3 percent (2 out of 32) of all the annual FTR market modeled outages expected to occur in the 2018/2019 planning period and submitted late were expected to cause congestion. Of all the annual FTR market modeled outages expected to occur in the 2017/2018 planning period and submitted late, 12.5 percent (4 out of 32) were expected to cause congestion.

Table 12-54 Annual FTR market modeled transmission facility outage requests by congestion and received status: 2017/2018 and 2018/2019

		2017/2018				2018/2019			
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	3	4	7	42.9%	5	9	14	35.7%
	>=2 weeks & <2 months	21	59	80	26.3%	19	61	80	23.8%
	>=2 months	40	91	131	30.5%	33	82	115	28.7%
	Total	64	154	218	29.4%	57	152	209	27.3%
Late	<2 weeks	0	2	2	0.0%	1	0	1	100.0%
	>=2 weeks & <2 months	1	8	9	11.1%	0	5	5	0.0%
	>=2 months	3	18	21	14.3%	1	25	26	3.8%
	Total	4	28	32	12.5%	2	30	32	6.3%

Table 12-55 shows that 18.8 percent of outage requests modeled in the annual FTR market for the 2018/2019 planning period and with a duration of two weeks or longer but shorter than two months were cancelled, compared to 34.8 percent for the 2017/2018 planning period. Table 12-55 also shows that 16.3 percent of outages requests modeled in the Annual FTR Market for the 2018/2019 planning period and with a duration of two months or longer were cancelled, compared to 12.5 percent for the 2017/2018 planning period.

Table 12-55 Annual FTR market modeled transmission facility outage requests by processed status: 2017/2018 and 2018/2019

		2017/2018		2018/2019	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	0	0.0%	11	73.3%
	Denied	0	0.0%	0	0.0%
	Approved	0	0.0%	0	0.0%
	Cancelled	2	22.2%	1	6.7%
	Revised	0	0.0%	1	6.7%
	Active	0	0.0%	0	0.0%
	Completed	7	77.8%	2	13.3%
	Total	9	100.0%	15	100.0%
>=2 weeks & <2 months	In Progress	7	7.9%	48	56.5%
	Denied	2	2.2%	0	0.0%
	Approved	0	0.0%	0	0.0%
	Cancelled	31	34.8%	16	18.8%
	Revised	0	0.0%	0	0.0%
	Active	0	0.0%	11	12.9%
	Completed	49	55.1%	10	11.8%
	Total	89	100.0%	85	100.0%
>=2 months	In Progress	29	19.1%	62	44.0%
	Denied	0	0.0%	2	1.4%
	Approved	2	1.3%	0	0.0%
	Cancelled	19	12.5%	23	16.3%
	Revised	0	0.0%	0	0.0%
	Active	5	3.3%	42	29.8%
	Completed	97	63.8%	12	8.5%
	Total	152	100.0%	141	100.0%

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the 2018/2019 planning period, 241 outage requests were modeled and 11,882 outage requests were not modeled in the Annual FTR Market. In the 2017/2018 planning period, 250 outage requests were modeled and 21,095 outage requests were not modeled in the Annual FTR Market.

Table 12-56 shows that 3.7 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 2018/2019 planning period compared to 23.0 percent in the 2017/2018 planning period.

Table 12-56 Transmission facility outage requests not modeled in Annual FTR Auction: 2017/2018 and 2018/2019

	2017/2018						2018/2019					
	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	1,352	8,017	85.6%	282	8,548	96.8%	1,926	4,191	68.5%	167	3,467	95.4%
>=2 weeks & <2 months	569	409	41.8%	139	1,023	88.0%	732	259	26.1%	144	432	75.0%
>=2 months	134	40	23.0%	214	368	63.2%	206	8	3.7%	201	149	42.6%
Total	2,055	8,466	80.5%	635	9,939	94.0%	2,864	4,458	60.9%	512	4,048	88.8%

Table 12-57 shows that 28.9 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 2018/2019 planning period. It also shows that 82.9 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.

Table 12-57 Late transmission facility outage requests not modeled in Annual FTR Auction and submitted after annual bidding opening date: 2017/2018 and 2018/2019

	2017/2018			2018/2019		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	7,111	8,548	83.2%	2,558	3,467	73.8%
>=2 weeks & <2 months	900	1,023	88.0%	225	432	52.1%
>=2 months	305	368	82.9%	43	149	28.9%
Total	8,316	9,939	83.7%	2,826	4,048	69.8%

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.[68] Table 12-58 and Table 12-59 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-60 and Table

68 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).

12-61 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

Table 12-58 shows that on average, 27.9 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 2018/2019 planning period. On average, 30.6 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.

Table 12-58 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: 2017/2018 and 2018/2019

	2017/2018				2018/2019			
Month	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
Jun	134	116	250	46.4%	208	106	314	33.8%
Jul	83	72	155	46.5%	136	71	207	34.3%
Aug	100	73	173	42.2%	137	78	215	36.3%
Sep	394	125	519	24.1%	465	136	601	22.6%
Oct	598	162	760	21.3%	542	185	727	25.4%
Nov	453	177	630	28.1%				
Dec	330	142	472	30.1%				
Jan	194	78	272	28.7%				
Feb	214	125	339	36.9%				
Mar	391	168	559	30.1%				
Apr	444	204	648	31.5%				
May	396	203	599	33.9%				
Avg	311	137	448	30.6%	298	115	413	27.9%

Table 12-59 shows that on average, 19.2 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2018/2019 planning period. On average, 19.0 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2017/2018 planning period.

Table 12-59 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: 2017/2018 and 2018/2019

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Percent Cancelled
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%
	Apr	55	1	20	115	0	202	255	648	17.7%
	May	20	11	16	108	0	145	299	599	18.0%
	Avg	39	4	11	85	1	125	182	448	19.0%
2018/2019	Jun	22	11	10	57	0	60	154	314	18.2%
	Jul	11	4	6	38	0	60	88	207	18.4%
	Aug	19	3	2	38	1	65	87	215	17.7%
	Sep	77	11	22	143	1	163	184	601	23.8%
	Oct	180	5	21	132	3	234	152	727	18.2%
	Avg	62	7	12	82	1	116	133	413	19.2%

Table 12-60 shows that on average, 11.0 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 2018/2019 planning period, compared to 10.5 percent in the 2017/2018 planning period. On average, 69.8 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 2018/2019 planning period, compared to 70.3 percent in the 2017/2018 planning period.

Table 12-60 Transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction: 2017/2018 and 2018/2019

	2017/2018						2018/2019					
	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	642	96	13.0%	310	847	73.2%	761	116	13.2%	389	830	68.1%
Jul	294	48	14.0%	245	608	71.3%	393	64	14.0%	273	641	70.1%
Aug	341	28	7.6%	211	651	75.5%	489	62	11.3%	263	711	73.0%
Sep	860	83	8.8%	256	599	70.1%	838	126	13.1%	286	709	71.3%
Oct	986	89	8.3%	346	867	71.5%	1,310	44	3.2%	354	699	66.4%
Nov	820	78	8.7%	365	791	68.4%						
Dec	610	68	10.0%	324	693	68.1%						
Jan	566	73	11.4%	286	746	72.3%						
Feb	593	49	7.6%	340	700	67.3%						
Mar	1,071	216	16.8%	340	802	70.2%						
Apr	1,204	118	8.9%	447	851	65.6%						
May	1,209	143	10.6%	464	1,083	70.0%						
Avg	766	91	10.5%	328	770	70.3%	758	82	11.0%	313	718	69.8%

Table 12-61 shows that on average, 66.9 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 2018/2019 planning period, compared to 68.3 percent in the 2017/2018 planning period.

Table 12-61 Late transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction and submitted after monthly bidding opening date: 2017/2018 and 2018/2019

	2017/2018			2018/2019		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	622	847	73.4%	633	830	76.3%
Jul	410	608	67.4%	448	641	69.9%
Aug	473	651	72.7%	506	711	71.2%
Sep	406	599	67.8%	480	709	67.7%
Oct	595	867	68.6%	333	699	47.6%
Nov	490	791	61.9%			
Dec	508	693	73.3%			
Jan	493	746	66.1%			
Feb	457	700	65.3%			
Mar	569	802	70.9%			
Apr	560	851	65.8%			
May	731	1,083	67.5%			
Avg	526	770	68.3%	480	718	66.9%

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.[69]

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 May 5, 2018, Figure 12-4 shows that: there were 443 approved or active outages seen by market participants before the day-ahead market was closed; there were 329 outage requests included in the day-ahead market model; there were 315 outage request included in both sets of outage; there were 128 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 14 outage requests included in day-ahead market model but not available to market participants prior to the day-ahead market.

Figure 12-4 Illustration of day-ahead market analysis: May 5, 2018

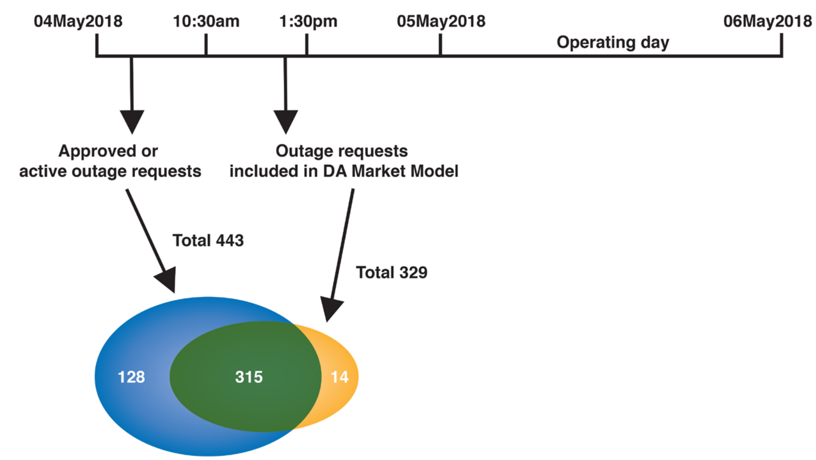


Figure 12-5 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.

69 PJM. "Manual 3: Transmission Operations," Rev. 53 (June 1, 2018) at 74.

Figure 12-5 Approved or active outage requests: January 2015 through September 2018

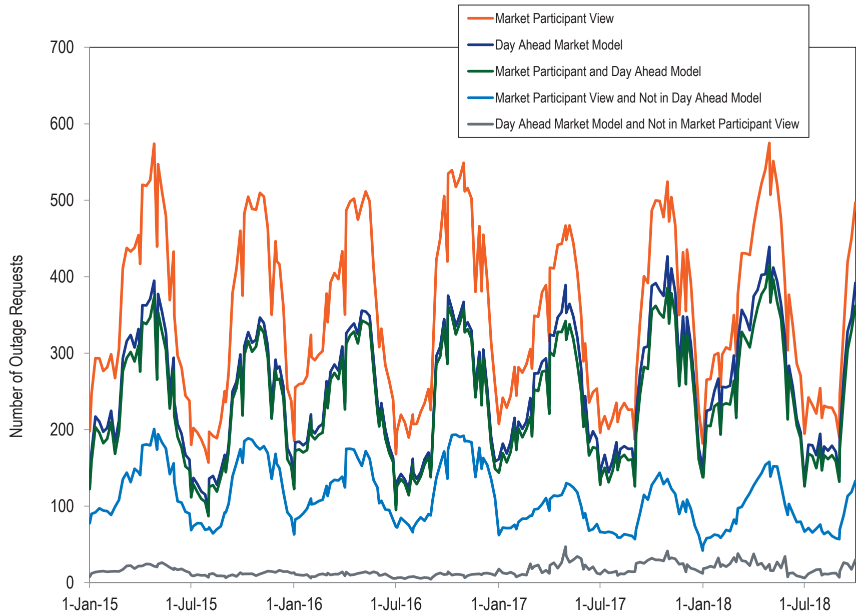


Figure 12-6 compares the weekly average number of outages included as inputs to the day-ahead market by PJM with the outages that actually occurred during the operating day.

Figure 12-6 Day-ahead market model outages: January 2015 through September 2018

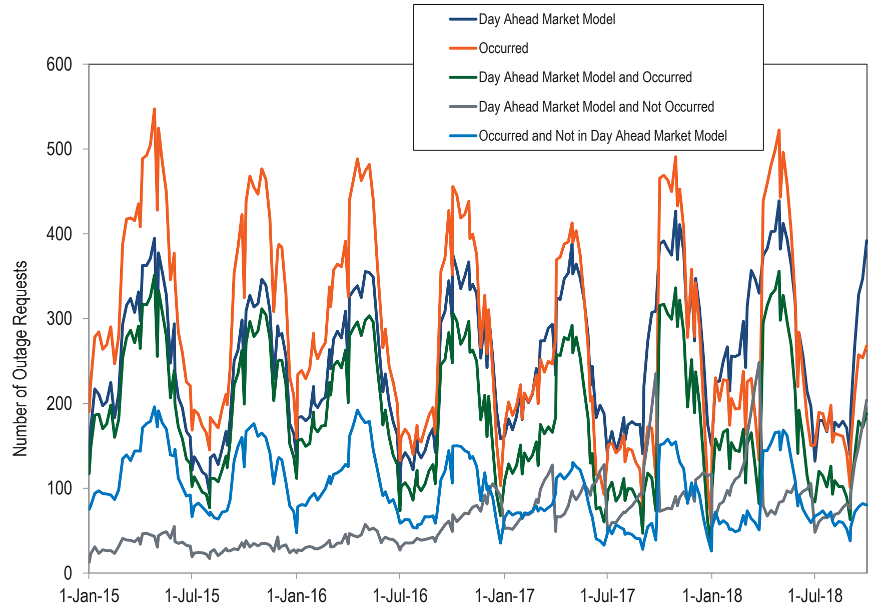


Figure 12-7 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

Figure 12-7 Approved or active outage requests: January 2015 through September 2018

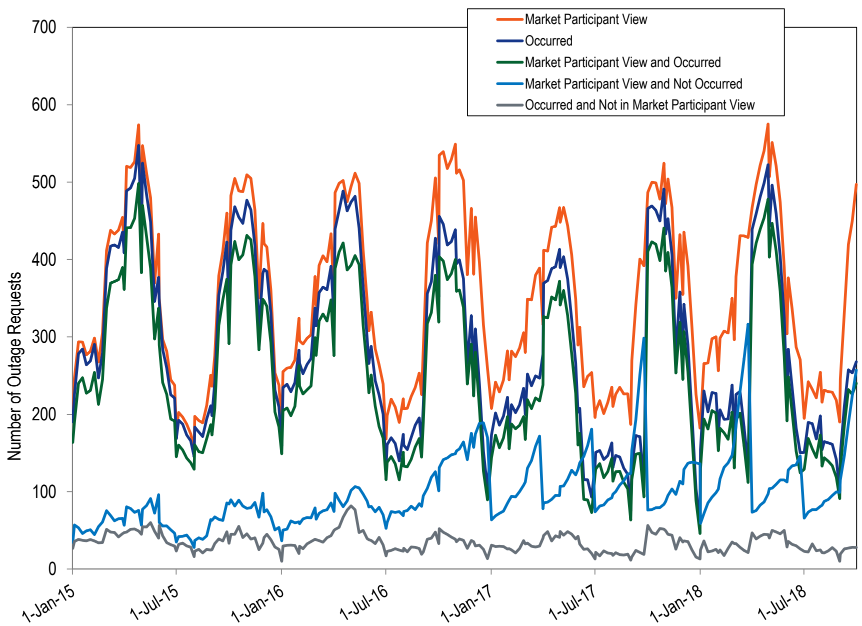


Figure 12-5, Figure 12-6, and Figure 12-7 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or 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.