Generation and Transmission Planning[1]

Overview

Generation Interconnection Planning

Existing Generation Mix

- As of March 31, 2019, PJM had a total installed capacity of 198,422.2 MW, of which 55,919.4 MW (28.2 percent) are coal fired steam units, 47,591.6 MW (24.0 percent) are combined cycle units and 34,257.6 MW (17.3 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 AEP Zone has the most total installed capacity of any PJM zone. Of the 198,422.2 MW of PJM total installed capacity, 31,643.0 MW (15.9 percent) are in the AEP Zone, of which 14,727.8 MW (46.5 percent) are coal fired steam units, 6,990.0 MW (22.1 percent) are combined cycle units and 2,071.0 MW (6.5 percent) are nuclear units.
- Pennsylvania has the most total installed capacity of any PJM state. Of the 198,422.2 MW of installed capacity, 46,087.5 MW (23.2 percent) are in Pennsylvania, of which 9,415.7 MW (20.4 percent) are coal fired steam units, 15,021.5 MW (32.6 percent) are combined cycle units and 9,648.8 MW (20.9 percent) are nuclear units.
- Of the 198,422.2 MW of installed capacity, 74,990.0 MW (37.8 percent) are from units older than 40 years, of which 40,145.2 MW (53.5 percent) are coal fired steam units, 532 MW (0.7 percent) are combined cycle units and 16,044.9 MW (21.4 percent) are nuclear units.

1 Totals presented in this section include corrections to historical data and may not match totals presented in previous reports.

Generation Retirements[2]

- There are 46,436.9 MW of generation that have been, or are planned to be, retired between 2011 and 2022, of which 32,486.2 MW (70.0 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 three months of 2019, 1,689.0 MW of generation retired. The largest generators that retired in the first three months of 2019 were the two 830.0 MW Mansfield coal fired steam units owned by FirstEnergy Corporation and located in the American Transmission Systems Inc. (ATSI) Zone. Of the 1,689.0 MW of generation that retired, 1,660.0 MW (98.3 percent) were located in the ATSI Zone.
- There are 13,376.8 MW of generation that have requested retirement after March 31, 2019, of which 5,131.0 MW (38.4 percent) are located in the ATSI Zone. Of the ATSI generation requesting retirement, 2,960.0 MW (57.7 percent) are coal fired steam units and 2,134.0 MW (41.6 percent) are nuclear units. The largest generator pending retirement is the 1,240.0 MW Perry U1 Nuclear Generating Unit located in the ATSI Zone.

Generation Queue[3]

- The total MW in generation queues, in the status of active, under construction or suspended, at the end of 2018 was 114,953.7 MW. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service. Of the 114,953.7 MW in the queue on December 31, 2018, only 67,238.1 MW were active, under construction or suspended on March 31, 2019. The total MW in queues increased by 56,905.0 MW (84.6 percent) from 67,238.1 MW at the end of 2018 to 124,143.0 MW on March 31, 2019.
- A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units enter the queue and coal fired steam units retire. As of March 31, 2019, there were 50,346.9 MW

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>.

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 March 31, 2019, there were only 133.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.

- As of March 31, 2019, 4,334 projects, representing 548,811.2 MW, have entered the queue process since its inception in 1998. Of those, 835 projects, representing 65,091.8 MW, went into service. Of the projects that entered the queue process, 2,449 projects, representing 359,576.4 MW (65.5 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- As of March 31, 2019, 124,143.0 MW of capacity were in generation request queues in the status of active, under construction or suspended. Of the total 124,143.0 MW in the queue, 56,255.2 MW (45.3 percent) have reached at least the system impact study (SIS) milestone and 67,887.8 MW (54.7 percent) have not received a completed SIS. Based on historical completion rates, (applying the unit type specific completion rates for those projects that have reached the system impact study, facility study agreement or construction service agreement milestone, and using the overall completion rates for those projects that have not yet reached the system impact study milestone), 34,184 MW of new generation in the queue are expected to go into service.

Regional Transmission Expansion Plan (RTEP)

Backbone Facilities

- There are currently six backbone projects under development, the Surry-Skiffes Creek 500kV Line, the Loudoun-Brambleton 500kV Line, the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV, the conversion of the Robinson Park-Sorenson lines to double circuit 345kV and the Meadow Lake-Reynolds 345kV Line rebuild.[4]

Market Efficiency Process

- PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. This analysis evaluated the reasons for congestion on 25 flowgates.[5] The proposal window was open from August 12, 2013, through September 26, 2013. PJM received 38 proposals from six entities. One project was approved by the PJM Board.
- Through March 31, 2019, PJM has completed two market efficiency cycles under Order No. 1000. In the first cycle, PJM received 93 proposals for 57 identified sources of congestion. In the second cycle, PJM received 96 proposals for four identified sources of congestion. The proposal window for 2018/2019 opened on November 1, 2018, and closed on February 28, 2019. PJM received 22 proposals for one identified source of congestion.
- 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.
- There are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. PJM's benefit/cost analysis does not correctly account for the costs of increased congestion associated with market efficiency projects.

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

4 See PJM, "*2018 RTEP Process Scope and Input Assumptions White Paper*," at 25. <https://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en>.

5 Historical congestion drivers are identified using the historical congestion tables presented in the *2018 State of the Market Report for PJM*, Section 11: Congestion and Marginal Losses, historical analysis of real time constraints, the NERC Book of Flowgates and PROMOD simulations.

recommended projects to their boards in December, 2017, and both boards approved all five projects.[6]

- 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 presented the two recommended projects to their boards in December, 2018, and both boards approved the projects.[7]

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."[8] Supplemental projects are exempt from the competitive planning process.
- The average number of supplemental projects in each expected in service year increased by 615.0 percent, from 20 for years 1998 through 2007 (pre Order 890) to 143 for years 2008 through 2019 (post Order 890).
- The process for designating projects as supplemental projects should be reviewed and modified to ensure that the supplement project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build the project.

6 See PJM, "*MISO PJM IPSAC*" (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.
7 See PJM, "*MISO PJM IPSAC*" (January 18, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20190118/20190118-ipsac-presentation.ashx>.
8 See PJM, "*Transmission Construction Status*" (January 23, 2018) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, 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.[9] 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.
- End of life transmission projects should be subject to a transparent, robust and clearly defined mechanism to permit competition to build the project.

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[10] On February 12, 2019, the PJM Board of Managers authorized an additional $272.0 million in transmission upgrades and additions. As of March 31, 2019, the PJM Board has approved $38.5 billion in system enhancements since 1999.

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 nonincumbent transmission. These recommendations will ensure that the process is an open and transparent process that results in the most cost effective solutions.

9 See PJM Operating Agreement Schedule 6 § 1.5.8(o).
10 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

- On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions.

Qualifying Transmission Upgrades (QTU)

- A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit into an LDA and can be offered into capacity auctions as capacity.
- QTU projects are submitted and tracked through the PJM queue.[11] A total of 51 QTU projects have entered the queue since 2007. Of the 51 submitted QTU projects, 37 projects (72.5 percent) have been withdrawn, five (10.0 percent) are in service and nine (17.5 percent) are currently in active development.

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.[12]
- There were 17,641 transmission outage requests submitted in the first ten months of 2018/2019 planning period. Of the requested outages, 75.8 percent of the requested outages were planned for less than or equal to five days and 8.8 percent of requested outages were planned for greater than 30 days. Of the requested outages, 49.4 percent were late according to the rules in PJM's Manual 3.

11 See PJM "New Services Queue," at <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.
12 PJM, "Manual 03: Transmission Operations," Rev. 54 (Dec. 10, 2018).

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, or the conversion from CP to energy only status, be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[13] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to ensure that CIRs are terminated within one year if units cannot qualify to be capacity resources and, if requested, after one CP must offer exception to permit the issue of CP status to be addressed. (Priority: Low. First reported 2018. 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

13 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

go into service. (Priority: Medium. First reported 2014. Status: Partially adopted.)

- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that PJM modify the rules governing benefit/cost analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all costs, including increasesd congestion costs and the risk of project cost increases, in all zones are included. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM modify the rules governing the market efficiency process benefit/cost analysis so that competing projects with different in service dates are evaluated on a symmetric, comparable basis. (Priority: Medium. First reported 2018. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent 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 nonincumbent transmission providers. (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 nonincumbent 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: Medium. First reported 2015. Status: Not adopted.)

Cost Allocation

- 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.[14] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Facility Outages

- 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 nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process for nonincumbent 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 nonincumbent transmission. Another element of opening competition would be to consider

14 See the *2015 State of the Market Report for PJM*, Section 12: Generation and Transmission Planning, at p. 463, Cost Allocation Issues.

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, paid for by customers. 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.

The process for determining the reasonableness or purpose of supplemental transmission projects that are asserted to be not needed for reliability, economic efficiency or operational performance as defined under the RTEP process needs additional oversight and transparency. If there is a need for a supplemental project, that need should be clearly defined and there should be a transparent, robust and clearly defined mechanism to permit competition to build the project. If there is no defined need for of a supplemental project for reliability, economic efficiency or operational performance then the project should not be included in rates.

The inclusion of market efficiency transmission projects in the transmission planning process, in addition to reliability projects, effectively results in direct competition between generation and transmission to address congestion issues in the wholesale power market, including congestion in the energy and capacity markets but with a bias towards the transmission option. The role of the market efficiency process and its impact on competition should be more thoroughly evaluated. But PJM fails to explicitly address this fact in the design of the market efficiency process. While the market efficiency process and metrics require modification, for example to ensure that all congestion is measured, the role of the market efficiency process and its impact on competition should also be more thoroughly evaluated. Building transmission under cost of service regulation already provides a significant competitive advantage to transmission over generation which is built entirely based on market prices and for which investors take the risks. The risks of cost increases for transmission projects should also be incorporated in the cost benefit analysis.

There are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects. The current benefit/cost analysis for a regional project, for example, explicitly and incorrectly ignores the increased congestion in zones that results from an RTEP project when calculating the energy market benefits. All costs should be included in all zones and LDAs.

The benefit/cost analysis should also account for the fact that the transmission project costs are not subject to cost caps and may exceed the estimated costs by a wide margin. When actual costs exceed estimated costs, the cost benefit analysis is effectively meaningless and low estimated costs may result in inappropriately favoring transmission projects over market generation projects. The risk of cost increases for transmission projects should be incorporated in the cost benefit analysis.

The current rules governing the benefit/cost analysis evaluate competing projects with different in service dates on an asymmetric basis. Under the current rules, projects are evaluated on a present value, benefit/cost basis over a 15 year service horizon, starting with the in service date of the project. A better approach would be to establish a common end date for all evaluated competing projects so that the minimum included years for any evaluated project is 15 years. This means that if there were an RTEP year zero project and a RTEP year +2 project competing, the benefit/cost ratio analysis would include the benefits and costs for both projects for every year from RTEP year zero to RTEP+16. Under this approach all projects would be evaluated over an identical term rather than an artificially truncated term and all projects would be evaluated on a present value basis at year zero.[15]

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

15 See "Comments of the Independent Market Monitor for PJM," (January 11, 2019) <http://www.monitoringanalytics.com/Filings/2019/IMM_Comments_Docket_No_ER19-80_20190111.pdf>.

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.[16] As of March 31, 2019, PJM had an installed capacity of 198,422.2 MW, of which 55,919.4 MW (28.2 percent) are coal fired steam units, 47,591.6 MW (24.0 percent) are combined cycle units and 34,257.6 MW (17.3 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 AEP Zone has the most total installed capacity of any PJM zone. Of the 198,422.2 MW of PJM total installed capacity, 31,643.0 MW (15.9 percent) are in the AEP Zone, of which 14,727.8 MW (46.5 percent) are coal fired steam units, 6,990.0 MW (22.1 percent) are combined cycle units and 2,071.0 MW (6.5 percent) are nuclear units.

Table 12-1 Existing PJM capacity: March 31, 2019 (By zone and unit type (MW))[17]

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	2,790.0	31,643.0
APS	80.4	2,179.0	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	10,317.4
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	3,734.0	325.0	0.0	0.0	0.0	10,025.5
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	148.5	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	3,584.9	29,520.9
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	9,099.6	3,835.3	0.0	266.4	0.0	3,003.0	586.3	3,581.3	0.0	39.0	112.8	722.1	4,445.1	35.0	1,586.0	368.4	208.0	27,888.3
DPL	0.0	1,742.5	978.2	0.0	478.2	30.0	0.0	0.0	0.0	0.0	88.0	14.1	219.4	410.0	882.0	153.0	0.0	0.0	4,995.4
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	40.0	2,402.5	531.1	0.0	232.0	0.4	400.0	0.0	0.0	0.0	0.0	16.1	287.4	0.0	0.0	0.0	10.0	0.0	3,919.6
Met-Ed	0.0	2,101.0	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	3,533.9
OVEC	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	2,388.8	0.0	0.0	0.0	0.0	2,388.8
PECO	0.0	4,089.0	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	12,096.8
PENELEC	28.4	850.0	350.5	0.0	57.0	0.0	513.0	77.8	0.0	0.0	128.2	17.8	0.0	6,141.5	610.0	0.0	42.0	1,028.8	9,845.0
Pepco	0.0	1,729.5	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	6,461.9
PPL	20.0	5,558.5	252.0	0.0	150.1	0.0	0.0	706.6	2,520.0	0.0	17.0	24.7	15.0	2,590.9	2,449.0	10.0	29.0	216.5	14,559.3
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	15.0	205.6	0.0	3.0	0.0	179.1	0.0	9,355.8
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	2,961.0	0.0	0.0	0.0	0.0	5,061.7
Total	349.0	47,591.6	25,068.0	0.0	3,997.6	32.0	5,052.0	3,040.6	34,257.6	0.0	360.3	396.0	1,592.9	55,919.4	8,581.6	2,146.0	1,010.5	9,027.2	198,422.2

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

17 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. Pennsylvania has the most total installed capacity of any PJM state. Of the 198,422.2 MW of installed capacity, 46,087.5 MW (23.2 percent) are in Pennsylvania, of which 9,415.7 MW (20.4 percent) are coal fired steam units, 15,021.5 MW (32.6 percent) are combined cycle units and 9,648.8 MW (20.9 percent) are nuclear units.

Table 12-2 Existing PJM capacity: March 31, 2019 (By state and unit type (MW))

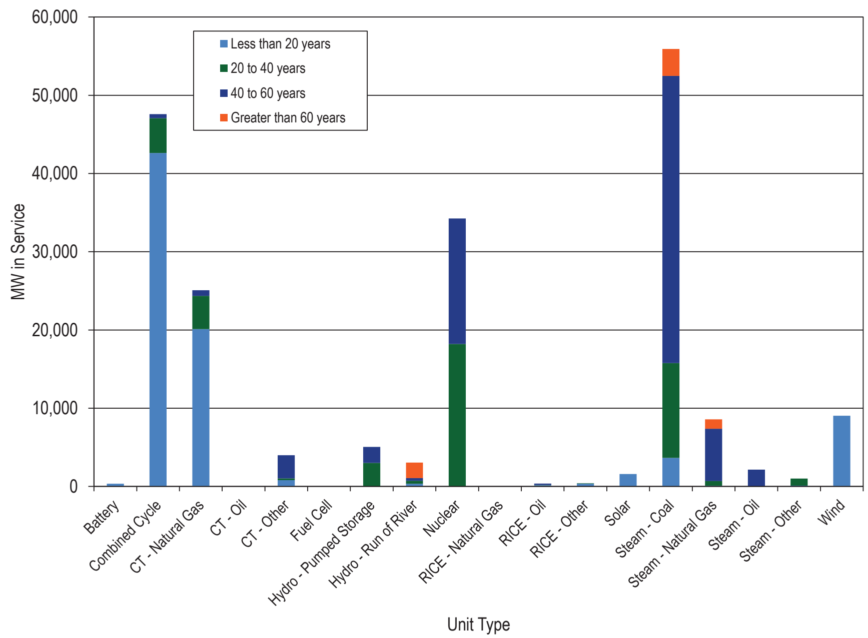
State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
DC	0.0	19.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.5
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	148.5	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	3,584.9	29,520.9
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	3,923.8	0.0	0.0	0.0	2,023.2	8,244.9
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	1,917.0	0.0	591.7	0.0	0.0	0.4	1,716.0	0.0	76.0	24.3	245.6	4,386.0	1,404.6	550.0	109.0	295.0	14,045.6
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	432.7	115.5	0.0	0.0	0.0	208.0	1,254.2
NJ	45.7	7,714.7	2,115.0	0.0	258.0	2.0	400.0	5.0	3,493.0	0.0	4.0	41.7	552.4	613.9	3.0	0.0	189.1	7.5	15,444.9
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	12,423.8	372.0	0.0	0.0	766.8	27,590.1
PA	49.9	15,021.5	1,542.7	0.0	1,454.6	0.0	1,583.0	1,445.7	9,648.8	0.0	176.8	95.1	18.0	9,415.7	3,821.0	10.0	294.0	1,510.7	46,087.5
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	8,934.6	4,172.3	0.0	603.4	0.0	3,069.0	460.1	3,581.3	0.0	33.0	118.8	319.4	3,324.6	495.0	1,586.0	368.4	0.0	27,065.9
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	2,961.0	0.0	0.0	0.0	0.0	5,061.7
Total	349.0	47,591.6	25,068.0	0.0	3,997.6	32.0	5,052.0	3,040.6	34,257.6	0.0	360.3	396.0	1,592.9	55,919.4	8,581.6	2,146.0	1,010.5	9,027.2	198,422.2

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of March 31, 2019. Of the 198,422.2 MW of installed capacity, 74,990.0 MW (37.8 percent) are from units older than 40 years, of which 40,145.2 MW (53.5 percent) are coal fired steam units, 532 MW (0.7 percent) are combined cycle units and 16,044.9 MW (21.4 percent) are nuclear units.

Table 12-3 PJM capacity (MW) by unit type and age (years): March 31, 2019

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	349.0	42,616.1	20,116.2	0.0	799.0	32.0	0.0	339.2	0.0	0.0	149.8	341.6	1,592.9	3,655.0	82.0	0.0	97.4	9,027.2	79,197.3
20 to 40	0.0	4,443.5	4,249.6	0.0	217.2	0.0	3,003.0	385.2	18,212.7	0.0	37.0	54.4	0.0	12,119.2	600.0	0.0	913.1	0.0	44,234.9
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	36,708.4	6,681.1	2,146.0	0.0	0.0	68,358.5
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	3,436.8	1,218.5	0.0	0.0	0.0	6,631.5
Total	349.0	47,591.6	25,068.0	0.0	3,997.6	32.0	5,052.0	3,040.6	34,257.6	0.0	360.3	396.0	1,592.9	55,919.4	8,581.6	2,146.0	1,010.5	9,027.2	198,422.2

Figure 12-1 PJM capacity (MW) by age (years): March 31, 2019



Generation Retirements[18]

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.[19] 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.[20]

Rules that preserve the Capacity Injection Rights (CIRs) associated with retired units, and with the conversion from Capacity Performance (CP) to energy only status, 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.[21] There are currently no rules governing the retention of CIRs when units want to convert to energy only status or require time to upgrade to retain CP status. The rules governing conversion or upgrades should be the same as the rules governing retired units. 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.[22] The MMU recognized the progress made in this rule change, but it did not fully address the issues. The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit, or conversion from CP to energy only status, be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[23]

18 See PJM, "Generator Deactivations," at <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
19 See OATT Section V and Attachment M–Appendix § IV.
20 See PJM, "Explaining Power Plant Retirements in PJM," at <http://learn.pjm.com/three-priorities/planning-for-the-future/explaining-power-plant-retirements.aspx>.
21 See OATT § 230.3.3.
22 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).
23 See "Comments of the Independent Market Monitor for PJM," Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

Generation Retirements 2011 through 2022

Table 12-4 shows that there are 46,436.9 MW of generation that have been, or are planned to be, retired between 2011 and 2022, of which 32,486.2 MW (70.0 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 2022

	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	3,251.5	996.0	148.0	108.0	0.0	5,607.7
Retirements 2019	0.0	0.0	0.0	0.0	19.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,660.0	0.0	10.0	0.0	0.0	1,689.0
Planned Retirements (April 2019 and later)	0.0	0.0	579.3	0.0	56.4	0.0	0.0	0.0	4,716.0	0.0	13.0	8.0	0.0	6,949.1	199.0	786.0	70.0	0.0	13,376.8
Total	41.0	425.0	2,284.3	0.0	1,834.5	0.0	0.5	0.0	5,330.5	0.0	57.1	41.9	0.0	32,486.2	2,065.5	1,658.0	202.0	10.4	46,436.9

Table 12-5 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2022, while Table 12-6 shows these retirements by state. Of the 46,436.9 MW of units that has been, or are planned to be, retired between 2011 and 2022, 32,486.2 MW (70.0 percent) are coal fired steam units. These coal fired steam units have an average age of 52.6 years and an average size of 195.7 MW. Over half of the retiring coal fired steam units, 59.9 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 2022

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	0.9%
Combustion Turbine	113	36.4	41.2	4,118.8	8.9%
Natural Gas	59	38.7	41.2	2,284.3	4.9%
Oil	0	0.0	0.0	0.0	0.0%
Other	54	34.0	41.2	1,834.5	4.0%
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	11.5%
RICE	23	4.4	29.3	99.0	0.2%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	11	5.2	46.1	57.1	0.1%
Other	12	3.5	12.4	41.9	0.1%
Solar	0	0.0	0.0	0.0	0.0%
Steam	197	153.9	46.1	36,411.7	78.4%
Coal	166	195.7	52.6	32,486.2	70.0%
Natural Gas	18	114.8	60.8	2,065.5	4.4%
Oil	6	276.3	45.7	1,658.0	3.6%
Other	7	28.9	25.1	202.0	0.4%
Wind	1	10.4	15.6	10.4	0.0%
Total	345	134.6	46.5	46,436.9	100.0%

Table 12-6 Retirements (MW) by unit type and state: 2011 through 2022

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	136.0	0.0	0.0	0.0	390.0
IL	0.0	0.0	296.0	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	1,932.5
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	347.5	0.0	105.6	0.0	0.0	0.0	0.0	0.0	0.0	3.8	0.0	635.0	171.0	0.0	0.0	0.0	1,262.9
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	10.0	0.0	6,060.9
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	14,669.4	0.0	0.0	0.0	0.0	17,162.6
PA	1.0	0.0	50.8	0.0	58.0	0.0	0.0	0.0	2,582.0	0.0	13.9	13.0	0.0	4,801.3	283.0	176.0	109.0	10.4	8,098.4
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	786.0	83.0	0.0	4,490.2
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	2,284.3	0.0	1,834.5	0.0	0.5	0.0	5,330.5	0.0	57.1	41.9	0.0	32,486.2	2,065.5	1,658.0	202.0	10.4	46,436.9

Figure 12-2 is a map of unit retirements between 2011 and 2022, with a mapping to unit names in Table 12-7.

Figure 12-2 Map of PJM unit retirements: 2011 through 2022

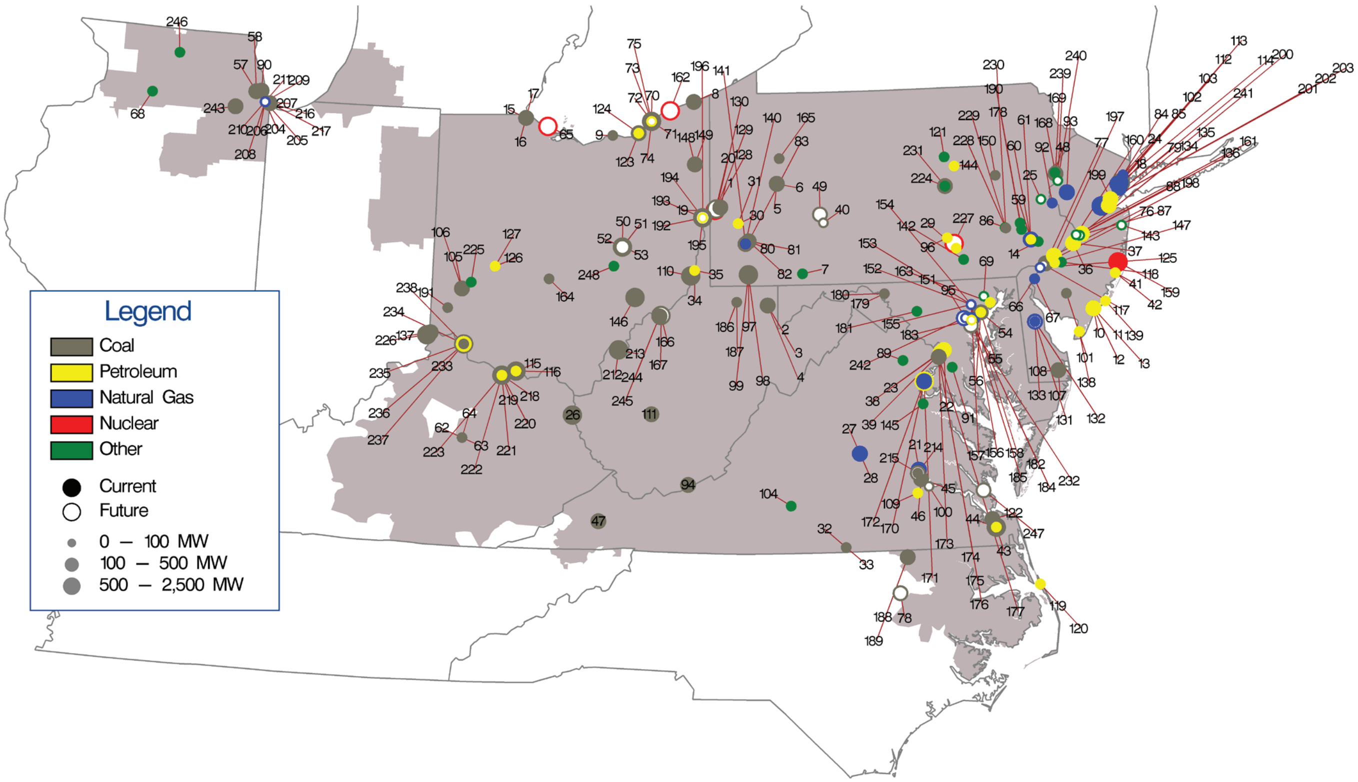


Table 12-7 Unit identification for map of PJM unit retirements: 2011 through 2022

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AES Beaver Valley	51	Conesville 4	101	Howard Down 10	151	Notch Cliff GT1	201	Sewaren 3
2	Albright 1	52	Conesville 5	102	Hudson 1	152	Notch Cliff GT2	202	Sewaren 4
3	Albright 2	53	Conesville 6	103	Hudson 2	153	Notch Cliff GT3	203	Sewaren 6
4	Albright 3	54	Crane 1	104	Hurt NUG	154	Notch Cliff GT4	204	Southeast Chicago CT11
5	Armstrong 1	55	Crane 2	105	Hutchings 1-3, 5-6	155	Notch Cliff GT5	205	Southeast Chicago CT12
6	Armstrong 2	56	Crane GT1	106	Hutchings 4	156	Notch Cliff GT6	206	Southeast Chicago CT5
7	Arnold (Green Mtn. Wind Farm	57	Crawford 7	107	Indian River 1	157	Notch Cliff GT7	207	Southeast Chicago CT6
8	Ashtabula 5	58	Crawford 8	108	Indian River 3	158	Notch Cliff GT8	208	Southeast Chicago CT7
9	Avon Lake 7	59	Cromby 1	109	Ingenco Petersburg	159	Oyster Creek	209	Southeast Chicago CT8
10	BL England 1	60	Cromby 2	110	Kammer 1-3	160	Pennsbury Generator Landfill 1	210	Southeast Chicago GT10
11	BL England 2	61	Cromby D	111	Kanawha River 1-2	161	Pennsbury Generator Landfill 2	211	Southeast Chicago GT9
12	BL England 3	62	Dale 1-2	112	Kearny 10	162	Perry U1 Nuclear Generating Unit	212	Sporn 1-4
13	BL England Diesel Units 1-4	63	Dale 3	113	Kearny 11	163	Perryman 2	213	Sporn 5
14	Barbados AES Battery	64	Dale 4	114	Kearny 9	164	Picway 5	214	Spruance NUG1 (Rich 1-2)
15	Bay Shore 2	65	Davis Besse U1 Nuclear Generating Unit	115	Killen 2	165	Piney Creek NUG	215	Spruance NUG2 (Rich 3-4)
16	Bay Shore 3	66	Deepwater 1	116	Killen CT	166	Pleasants Power Station U1	216	State Line 3
17	Bay Shore 4	67	Deepwater 6	117	Kimberly Clark Generator	167	Pleasants Power Station U2	217	State Line 4
18	Bayonne Cogen Plant (CC)	68	Dixon Lee Landfill Generator	118	Kinsley Landfill	168	Portland 1	218	Stuart 1
19	Beaver Valley U1 Nuclear Generating Unit	69	Eastern Landfill Gas Generator	119	Kitty Hawk GT 1	169	Portland 2	219	Stuart 2
20	Beaver Valley U2 Nuclear Generating Unit	70	Eastlake 1	120	Kitty Hawk GT 2	170	Possum Point 3	220	Stuart 3
21	Bellemeade	71	Eastlake 2	121	Koppers Co. IPP	171	Possum Point 4	221	Stuart 4
22	Benning 15	72	Eastlake 3	122	Lake Kingman	172	Possum Point 5	222	Stuart Diesels 1-4
23	Benning 16	73	Eastlake 4	123	Lake Shore 18	173	Potomac River 1	223	Stuart Diesels 1-4
24	Bergen 3	74	Eastlake 5	124	Lake Shore EMD	174	Potomac River 2	224	Sunbury 1-4
25	Bethlehem Renewable Energy Generator (Landfill)	75	Eastlake 6	125	MH50 Markus Hook Co-gen	175	Potomac River 3	225	Tait Battery
26	Big Sandy 2	76	Eddystone 1	126	Mad River CTs A	176	Potomac River 4	226	Tanners Creek 1-4
27	Bremo 3	77	Eddystone 2	127	Mad River CTs B	177	Potomac River 5	227	Three Mile Island Unit 1
28	Bremo 4	78	Edgecomb NUG (Rocky 1-2)	128	Mansfield 1	178	Pottstown LF (Moser)	228	Titus 1
29	Brunner Island Diesels	79	Edison 1-3	129	Mansfield 2	179	R Paul Smith 3	229	Titus 2
30	Brunot Island 1B	80	Elrama 1	130	Mansfield 3	180	R Paul Smith 4	230	Titus 3
31	Brunot Island 1C	81	Elrama 2	131	McKee 1	181	Reichs Ford Road Landfill Generator	231	Viking Energy NUG
32	Buggs Island 1 (Mecklenberg)	82	Elrama 3	132	McKee 2	182	Riverside 4	232	Wagner 2
33	Buggs Island 2 (Mecklenberg)	83	Elrama 4	133	McKee 3	183	Riverside 6	233	Walter C Beckjord 1
34	Burger 3	84	Essex 10-11	134	Mercer 1	184	Riverside 7	234	Walter C Beckjord 2
35	Burger EMD	85	Essex 12	135	Mercer 2	185	Riverside 8	235	Walter C Beckjord 3
36	Burlington 8,11	86	Evergreen Power United Corstack	136	Mercer 3	186	Riversville 5	236	Walter C Beckjord 4
37	Burlington 9	87	Fairless Hills Landfill A	137	Miami Fort 6	187	Riversville 6	237	Walter C Beckjord 5-6
38	Buzzard Point East Banks 1,2,4-8	88	Fairless Hills Landfill B	138	Middle 1-3	188	Roanoke Valley 1	238	Walter C Beckjord GT 1-4
39	Buzzard Point West Banks 1-9	89	Fauquier County Landfill	139	Missouri Ave B,C,D	189	Roanoke Valley 2	239	Warren County Landfill
40	Cambria CoGen	90	Fisk Street 19	140	Mitchell 2	190	Rolling Hills Landfill Generator	240	Warren County NUG
41	Cedar 1	91	GUDE Landfill	141	Mitchell 3	191	SMART Paper	241	Werner 1-4
42	Cedar 2	92	Gilbert 1-4	142	Modern Power Landfill NUG	192	Sammis 1-4	242	Westport 5
43	Chesapeake 1-4	93	Glen Gardner 1-8	143	Monmouth NUG landfill	193	Sammis 5	243	Will County 3
44	Chesapeake 7-10	94	Glen Lyn 5-6	144	Montour ATG	194	Sammis 6	244	Willow Island 1
45	Chesterfield 3	95	Gould Street Generation Station	145	Morris Landfill Generator	195	Sammis 7	245	Willow Island 2
46	Chesterfield 4	96	Harrisburg 4 CT	146	Muskingum River 1-5	196	Sammis Diesel	246	Winnebago Landfill
47	Clinch River 3	97	Hatfield's Ferry 1	147	National Park 1	197	Schuylkill 1	247	Yorktown 1-2
48	Columbia Dam Hydro	98	Hatfield's Ferry 2	148	Niles 1	198	Schuylkill Diesel	248	Zanesville Landfill
49	Colver Power Project	99	Hatfield's Ferry 3	149	Niles 2	199	Sewaren 1		
50	Conesville 3	100	Hopewell James River Cogeneration	150	Northeastern Power NEPCO	200	Sewaren 2		

Current Year Generation Retirements

Table 12-8 shows that in the first three months of 2019, 1,689.0 MW of generation retired. The largest generators that retired in the first three months of 2019 were the two 830.0 MW Mansfield coal fired steam units owned by FirstEnergy Corporation and located in the American Transmission Systems Incorporated (ATSI) Zone. Of the 1,689.0 MW of generation that retired, 1,660.0 MW (98.3 percent) were located in the ATSI Zone.

Table 12-8 Unit deactivations: January through March, 2019[24]

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Age (Years)	Retirement Date
FirstEnergy Corp.	Mansfield 1	830.0	Steam-Coal	ATSI	42.9	05-Feb-19
FirstEnergy Corp.	Mansfield 2	830.0	Steam-Coal	ATSI	41.4	05-Feb-19
Riverstone Holdings LLC	Montour ATG	10.0	Steam-Oil	PPL	45.9	18-Feb-19
Exelon Corporation	Riverside 7	19.0	CT-Other	BGE	48.6	14-Mar-19
Total		1,689.0				

Planned Generation Retirements

Table 12-9 shows that there are 13,376.8 MW of generation that have requested retirement after March 31, 2019, of which 5,131.0 MW (38.4 percent) are located in the ATSI Zone, 2,960.0 MW (57.7 percent) are coal fired steam units and 2,134.0 MW (41.6 percent) are nuclear units. The largest generator pending retirement is the 1,240.0 MW Perry U1 Nuclear Generating Unit located in the ATSI Zone.

Table 12-9 Planned retirement of PJM units: March 31, 2019

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Projected Deactivation Date
Dominion Resources, Inc.	Yorktown 1-2	323.0	Steam-Coal	Dominion	08-Mar-19
Novi Energy LLC	Hopewell James River Cogeneration	89.0	Steam-Coal	Dominion	31-Mar-19
Rockland Capital Energy Investments, LLC	BL England 2	155.0	Steam-Coal	AECO	30-Apr-19
NextEra Energy, Inc.	Monmouth NUG landfill	6.4	CT-Other	JCPL	31-May-19
Exelon Corporation	Bethlehem Renewable Energy Generator (Landfill)	5.0	RICE-Other	PPL	01-Jun-19
American Electric Power Company, Inc.	Conesville 5	400.0	Steam-Coal	AEP	01-Jun-19
American Electric Power Company, Inc.	Conesville 6	400.0	Steam-Coal	AEP	01-Jun-19
Exelon Corporation	Eastern Landfill Gas Generator	3.0	RICE-Other	BGE	01-Jun-19
Exelon Corporation	Gould Street Generation Station	97.0	Steam-Natural Gas	BGE	01-Jun-19
Starwood Capital Group LLC	MH50 Markus Hook Co-gen	50.8	CT-Natural Gas	PECO	01-Jun-19
Covanta Holding Corporation	Warren County NUG	10.0	Steam-Other	JCPL	01-Jun-19
Northern Star Generation Services, Llc	Cambria CoGen	88.0	Steam-Coal	PENELEC	07-Jun-19
Kimberly-Clark Corporation	Kimberly Clark Generator	3.3	Steam-Coal	PECO	24-Sep-19
Exelon Corporation	Three Mile Island Unit 1 Nuclear Generating Station	805.0	Nuclear	Met-Ed	30-Sep-19
Exelon Corporation	Riverside 8	20.0	CT-Other	BGE	01-Dec-19
Exelon Corporation	Southeast Chicago CT11	37.0	CT-Natural Gas	ComEd	01-Dec-19
Exelon Corporation	Southeast Chicago CT12	37.0	CT-Natural Gas	ComEd	01-Dec-19
Exelon Corporation	Southeast Chicago CT5	37.0	CT-Natural Gas	ComEd	01-Dec-19
Exelon Corporation	Southeast Chicago CT6	37.0	CT-Natural Gas	ComEd	01-Dec-19

24 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.

Table 12-9 Planned retirement of PJM units: March 31, 2019 (continued)

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Projected Deactivation Date
Exelon Corporation	Southeast Chicago CT7	37.0	CT-Natural Gas	ComEd	01-Dec-19
Exelon Corporation	Southeast Chicago CT8	37.0	CT-Natural Gas	ComEd	01-Dec-19
Exelon Corporation	Southeast Chicago GT10	37.0	CT-Natural Gas	ComEd	01-Dec-19
Exelon Corporation	Southeast Chicago GT9	37.0	CT-Natural Gas	ComEd	01-Dec-19
Ares Management LP	Spruance NUG1 (aka Spruance 1 Rich 1-2)	115.5	Steam-Coal	Dominion	12-Jan-20
FirstEnergy Corp.	Davis Besse U1 Nuclear Generating Unit	894.0	Nuclear	ATSI	31-May-20
FirstEnergy Corp.	Sammis 1-4	640.0	Steam-Coal	ATSI	31-May-20
American Electric Power Company, Inc.	Conesville 4	337.0	Steam-Coal	AEP	01-Jun-20
The AES Corporation	Conesville 4	127.8	Steam-Coal	AEP	01-Jun-20
Vistra Energy Corp	Conesville 4	312.0	Steam-Coal	AEP	01-Jun-20
Exelon Corporation	Fairless Hills Landfill A	30.0	Steam-Other	PECO	01-Jun-20
Exelon Corporation	Fairless Hills Landfill B	30.0	Steam-Other	PECO	01-Jun-20
Exelon Corporation	Notch Cliff GT1	14.0	CT-Natural Gas	BGE	01-Jun-20
Exelon Corporation	Notch Cliff GT2	14.0	CT-Natural Gas	BGE	01-Jun-20
Exelon Corporation	Notch Cliff GT3	14.0	CT-Natural Gas	BGE	01-Jun-20
Exelon Corporation	Notch Cliff GT4	14.0	CT-Natural Gas	BGE	01-Jun-20
Exelon Corporation	Notch Cliff GT5	14.6	CT-Natural Gas	BGE	01-Jun-20
Exelon Corporation	Notch Cliff GT6	15.6	CT-Natural Gas	BGE	01-Jun-20
Exelon Corporation	Notch Cliff GT7	14.5	CT-Natural Gas	BGE	01-Jun-20
Exelon Corporation	Notch Cliff GT8	16.0	CT-Natural Gas	BGE	01-Jun-20
Exelon Corporation	Pennsbury Generator Landfill 1	3.0	CT-Other	PECO	01-Jun-20
Exelon Corporation	Pennsbury Generator Landfill 2	3.0	CT-Other	PECO	01-Jun-20
Riverstone Holdings LLC	Wagner 2	135.0	Steam-Coal	BGE	01-Jun-20
Exelon Corporation	Westport 5	115.8	CT-Natural Gas	BGE	01-Jun-20
FirstEnergy Corp.	Colver Power Project	110.0	Steam-Coal	PENELEC	01-Sep-20
Ares Management LP	Edgecomb NUG (aka Edgecomb Rocky 1-2)	115.5	Steam-Coal	Dominion	31-Oct-20
FirstEnergy Corp.	Beaver Valley U1 Nuclear Generating Unit	892.0	Nuclear	DLCO	31-May-21
FirstEnergy Corp.	Perry U1 Nuclear Generating Unit	1,240.0	Nuclear	ATSI	31-May-21
Dominion Resources, Inc.	Possum Point 5	786.0	Steam-Oil	Dominion	31-May-21
FirstEnergy Corp.	Eastlake 6	24.0	CT-Other	ATSI	01-Jun-21
FirstEnergy Corp.	Mansfield 3	830.0	Steam-Coal	ATSI	01-Jun-21
City of Dover	McKee 3	102.0	Steam-Natural Gas	DPL	01-Jun-21
FirstEnergy Corp.	Sammis Diesel	13.0	RICE-Oil	ATSI	01-Jun-21
FirstEnergy Corp.	Beaver Valley U2 Nuclear Generating Unit	885.0	Nuclear	DLCO	31-Oct-21
FirstEnergy Corp.	Pleasants Power Station U1	639.0	Steam-Coal	APS	01-Jun-22
FirstEnergy Corp.	Pleasants Power Station U2	639.0	Steam-Coal	APS	01-Jun-22
FirstEnergy Corp.	Sammis 5	290.0	Steam-Coal	ATSI	01-Jun-22
FirstEnergy Corp.	Sammis 6	600.0	Steam-Coal	ATSI	01-Jun-22
FirstEnergy Corp.	Sammis 7	600.0	Steam-Coal	ATSI	01-Jun-22
Total		13,376.8			

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.[25] 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 one 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 AF1 began on October 1, 2018 and closed on March 31, 2019.

Projects that do not meet submission requirements are removed from the queue. All projects that have entered 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.[26] 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.[27]

The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result.[28] 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.

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.

25 See OATT Parts IV & VI.
26 See "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 13 (Aug.23, 2018).
27 PJM does not track the duration of suspensions or PJM termination of projects.
28 See *PJM Interconnection, L.L.C.*, Docket No. ER12-1177 (Feb. 29, 2012).

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 March 31, 2019, 124,143.0 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.[29]

The total MW in generation queues, in the status of active, under construction or suspended, at the end of 2018 was 114,953.7 MW. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service. Of the 114,953.7 MW in the queue on December 31, 2018, only 67,238.1 MW were active, under construction or suspended on March 31, 2019. The total MW in queues increased by 56,905.0 MW (84.6 percent) from 67,238.1 MW at the end of 2018 to 124,143.0 MW on March 31, 2019. Table 12-11 shows MW in queues by expected completion year and MW changes in the queue between December 31, 2018, and March 31, 2019, for ongoing projects, i.e. projects with the status active, under construction or suspended.[30]

Table 12-11 Queue comparison by expected completion year (MW): December 31, 2018 and March 31, 2019[31]

			Year Change	
Year	As of 12/31/2018	As of 03/31/2019	MW	Percent
2008	12.0	12.0	0.0	0.0%
2009	0.0	0.0	0.0	0.0%
2010	0.0	0.0	0.0	0.0%
2011	102.5	102.5	0.0	0.0%
2012	72.2	33.2	(39.0)	(54.0%)
2013	210.5	210.5	0.0	0.0%
2014	25.0	10.0	(15.0)	(60.0%)
2015	420.4	214.6	(205.8)	(49.0%)
2016	1,838.5	702.3	(1,136.2)	(61.8%)
2017	3,279.1	2,170.7	(1,108.4)	(33.8%)
2018	10,785.7	5,210.9	(5,574.8)	(51.7%)
2019	18,309.4	19,431.2	1,121.8	6.1%
2020	22,621.9	27,725.1	5,103.2	22.6%
2021	7,100.0	30,020.4	22,920.4	322.8%
2022	2,460.9	20,084.0	17,623.1	716.1%
2023	0.0	8,499.5	8,499.5	0.0%
2024	0.0	5,383.8	5,383.8	0.0%
2025	0.0	2,286.9	2,286.9	0.0%
2026	0.0	445.2	445.2	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	67,238.1	124,143.0	56,905.0	84.6%

Table 12-12 shows the project status changes in more detail and how scheduled queue capacity has changed between December 31, 2018, and March 31, 2019. For example, 74,977.3 MW entered the queue in the first three months of 2019. Of those 74,977.3 MW, 18,052.5 MW have been withdrawn. Of the total 71,201.4 MW marked as active on December 31, 2018, 15,901.6 MW were withdrawn, 3,221.2 MW were suspended, 852.3 MW started construction, and

29 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>.

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

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

923.6 MW went into service by March 31, 2019. Analysis of projects that were suspended on December 31, 2018 show that 3,665.1 MW came out of suspension and are now active as of March 31, 2019.

Table 12-12 Change in project status (MW): December 31, 2018 to March 31, 2019

		Status at 3/31/2019				
Status at 12/31/2018	Total at 12/31/2018	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2019)	0.0	56,905.0	19.8	0.0	0.0	18,052.5
Active	71,201.4	50,302.7	923.6	852.3	3,221.2	15,901.6
In Service	51,674.6	0.0	51,672.7	0.0	0.0	1.9
Under Construction	18,754.2	389.9	12,335.6	5,172.8	544.0	311.9
Suspended	9,356.1	3,665.1	140.0	0.0	3,090.1	2,460.9
Withdrawn	322,847.7	0.0	0.0	0.0	0.0	322,847.7
Total	473,833.9	111,262.7	65,091.8	6,025.1	6,855.3	359,576.4

On March 31, 2019, 124,143.0 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 111,262.7 MW in the status of Active on March 31, 2019, 36,863.1 MW (33.1 percent) were combined cycle projects. Of the 6,025.1 MW in the status of under construction, 3,375.1 MW (56.0 percent) were combined cycle projects.

Table 12-13 Current project status (MW) by unit type: March 31, 2019

	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	1,570.9	36,863.1	4,599.9	14.0	0.0	0.0	1,000.0	20.5	123.5	91.9	4.0	6.8	39,452.9	85.0	94.0	0.0	40.0	27,296.3	111,262.7
Suspended	66.3	4,769.1	219.9	0.0	0.0	0.0	0.0	0.0	0.0	59.7	0.0	0.0	418.3	0.0	0.0	0.0	16.0	1,306.0	6,855.3
Under Construction	24.6	3,375.1	253.0	0.0	3.2	0.0	0.0	22.7	44.0	21.2	0.0	0.0	372.8	48.0	0.0	0.0	62.5	1,798.0	6,025.1
Total	1,661.7	45,007.3	5,072.8	14.0	3.2	0.0	1,000.0	43.2	167.5	172.8	4.0	6.8	40,244.0	133.0	94.0	0.0	118.5	30,400.3	124,143.0

A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units enter the queue and coal fired steam units retire. As of March 31, 2019, there were 50,346.9 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 March 31, 2019, there were only 133.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.

There are 6,949.1 MW of coal fired steam capacity and 778.3 MW of natural gas capacity slated for deactivation between March 31, 2019, and December 31, 2022 (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 March 31, 2019, there are 124,143.0 MW of capacity in queues that are not yet in service or withdrawn, of which 5.5 percent are suspended, 4.9 percent are under construction and 89.6 percent have not begun construction.

Table 12-14 Capacity in PJM queues (MW): March 31, 2019[32]

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	93.1	0.0	0.0	485.3	578.4
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	0.0	504.8	0.0	0.0	3,705.6	4,210.4
N Expired 31-Jan-05	39.0	2,398.8	0.0	0.0	8,090.3	10,528.0
O Expired 31-Jul-05	0.0	1,665.2	225.0	0.0	5,466.8	7,357.0
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	600.0	1,986.4	0.0	440.0	19,668.9	22,695.3
S Expired 31-Jul-07	70.0	3,543.5	0.0	0.0	12,396.5	16,010.0
T Expired 31-Jan-08	0.0	4,046.5	150.0	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	400.0	267.5	260.0	300.0	15,952.2	17,179.7
U3 Expired 31-Oct-08	100.0	333.0	0.0	0.0	2,535.6	2,968.6
U4 Expired 31-Jan-09	300.0	85.2	0.0	0.0	4,645.0	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	0.0	989.9	16.1	150.0	3,475.1	4,631.1
V3 Expired 31-Oct-09	200.0	912.0	0.0	20.0	3,822.7	4,954.7
V4 Expired 31-Jan-10	0.0	748.8	0.0	200.0	3,508.0	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	351.7	0.0	23.0	3,018.7	3,403.4
W3 Expired 31-Oct-10	0.0	490.3	57.7	100.0	8,574.1	9,222.0
W4 Expired 31-Jan-11	0.0	1,101.8	399.9	0.0	4,120.6	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	2,948.9	0.0	0.0	2,419.4	5,368.3
Y1 Expired 30-Apr-12	34.0	1,795.5	452.0	72.0	5,721.7	8,075.2
Y2 Expired 31-Oct-12	378.3	1,051.8	387.1	200.0	9,276.5	11,293.7
Y3 Expired 30-Apr-13	0.0	1,386.3	244.2	0.0	4,609.2	6,239.6
Z1 Expired 31-Oct-13	1,013.3	2,928.0	146.5	19.9	4,017.1	8,124.8
Z2 Expired 30-Apr-14	211.6	2,278.4	574.0	33.0	3,003.8	6,100.8
AA1 Expired 31-Oct-14	3,118.0	1,129.7	1,243.0	431.1	6,076.9	11,998.7
AA2 Expired 30-Apr-15	4,931.2	550.9	660.7	770.0	9,153.5	16,066.3
AB1 Expired 31-Oct-15	9,507.2	1,056.5	43.8	101.1	9,744.0	20,452.6
AB2 Expired 31-Mar-16	7,378.2	142.5	119.0	1,178.6	6,399.1	15,217.4
AC1 Expired 30-Sep-16	11,585.3	234.7	198.0	1,258.7	6,798.9	20,075.6
AC2 Expired 30-Apr-17	4,965.4	94.0	0.6	43.9	7,517.8	12,621.6
AD1 Expired 30-Sep-17	8,819.0	21.2	75.0	35.0	2,357.9	11,308.1
AD2 Expired 31-Mar-18	11,937.3	19.8	0.0	0.0	8,483.4	20,440.5
AE1 Expired 30-Sep-18	22,599.6	0.0	0.0	0.0	11,014.9	33,614.4
AE2 Through 31-Mar-19	23,011.8	0.0	0.0	0.0	105.6	23,117.4
Total	111,262.7	65,091.8	6,025.1	6,855.3	359,576.4	548,811.2

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

Table 12-15 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of March 31, 2019, 124,143.0 MW of capacity were in generation request queues for construction through 2029.[33] Table 12-15 also shows the planned retirements for each zone.

Table 12-15 Queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): March 31, 2019[34]

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 Retirements
EMAAC	AECO	100.0	1,068.6	230.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	456.4	0.0	0.0	0.0	0.0	2,803.6	4,658.6	155.0
	DPL	21.0	451.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	1,542.7	0.0	0.0	0.0	0.0	599.8	2,620.5	102.0
	JCPL	114.9	1,175.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	192.9	0.0	0.0	0.0	0.0	5,943.2	7,626.0	16.4
	PECO	0.0	102.0	29.0	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	247.0	120.1
	PSEG	2.0	3,710.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	142.8	0.0	0.0	0.0	0.0	0.0	3,855.3	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	60.0	0.0	0.0	0.0	0.0	0.0	60.0	0.0
	EMAAC Total	237.8	6,507.1	459.0	0.0	0.0	0.0	0.0	0.0	94.0	0.0	4.0	6.0	2,412.9	0.0	0.0	0.0	0.0	9,346.6	19,067.4	393.5
SWMAAC	BGE	0.1	0.0	153.6	14.0	0.0	0.0	0.0	0.0	45.5	1.3	0.0	0.0	4.0	0.0	0.0	0.0	0.0	0.0	218.5	487.5
	Pepco	0.0	1,177.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	120.1	0.0	0.0	0.0	0.0	0.0	1,297.7	0.0
	SWMAAC Total	0.1	1,177.6	153.6	14.0	0.0	0.0	0.0	0.0	45.5	1.3	0.0	0.0	124.1	0.0	0.0	0.0	0.0	0.0	1,516.2	487.5
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	679.6	0.0	0.0	0.0	0.0	0.0	1,278.5	805.0
	PENELEC	0.0	1,368.0	500.9	0.0	0.0	0.0	0.0	0.0	0.0	119.6	0.0	0.0	770.9	0.0	0.0	0.0	0.0	290.3	3,049.7	198.0
	PPL	238.8	2,205.8	0.0	0.0	0.0	0.0	1,000.0	0.0	0.0	0.0	0.0	0.0	536.2	0.0	0.0	0.0	16.0	388.3	4,385.1	5.0
	WMAAC Total	238.8	4,172.7	500.9	0.0	0.0	0.0	1,000.0	0.0	0.0	119.6	0.0	0.0	1,986.7	0.0	0.0	0.0	16.0	678.6	8,713.3	1,008.0
Non-MAAC	AEP	459.0	8,016.0	1,097.0	0.0	3.2	0.0	0.0	0.0	28.0	12.0	0.0	0.8	11,134.4	101.0	30.0	0.0	40.0	6,009.3	26,930.7	1,576.8
	APS	144.0	8,629.7	120.0	0.0	0.0	0.0	0.0	15.0	0.0	39.9	0.0	0.0	1,851.8	0.0	0.0	0.0	0.0	1,103.4	11,903.8	1,278.0
	ATSI	8.8	5,805.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,319.0	0.0	0.0	0.0	0.0	816.1	8,018.8	5,131.0
	ComEd	210.9	6,709.2	1,238.0	0.0	0.0	0.0	0.0	22.7	0.0	0.0	0.0	0.0	2,933.5	0.0	64.0	0.0	0.0	9,225.2	20,403.4	296.0
	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	1,137.0	12.0	0.0	0.0	0.0	100.0	2,418.9	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	80.0	0.0	0.0	0.0	0.0	0.0	305.0	1,777.0
	Dominion	302.6	2,840.0	1,156.3	0.0	0.0	0.0	0.0	5.5	0.0	0.0	0.0	0.0	15,472.6	0.0	0.0	0.0	62.5	3,121.2	22,960.7	1,429.0
	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	1,412.0	0.0	0.0	0.0	0.0	0.0	1,485.0	0.0
	OVEC	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
	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	1,185.0	33,149.9	3,959.3	0.0	3.2	0.0	0.0	43.2	28.0	51.9	0.0	0.8	35,720.3	133.0	94.0	0.0	102.5	20,375.1	94,846.2	11,487.8
	Total	1,661.7	45,007.3	5,072.8	14.0	3.2	0.0	1,000.0	43.2	167.5	172.8	4.0	6.8	40,244.0	133.0	94.0	0.0	118.5	30,400.3	124,143.0	13,376.8

33 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 derated wind resources to 13 percent of nameplate capacity until there is operational data to support a different conclusion. PJM derated solar resources to 38 percent of nameplate capacity. Effective June 1, 2017, PJM adjusted the derates of wind and solar resources. The capacity factor derates for wind resources are dependent on the wind farm locations and have an average derate of 16.2 percent. The capacity factor derates for solar resources are dependent on the solar installation type and have an average derate of 46.7 percent. Based on the derating of 30,400.3 MW of wind resources and 40,244.0 MW of solar resources, using the average derate factors, the 124,143.0 MW currently under construction, suspended or active in the queue would be reduced to 77,217.6 MW.

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

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, but the actual calculation of commercial probability factors is less than transparent.[35] 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 2,449 projects withdrawn, 1,194 (48.7 percent) were withdrawn before the system impact study was completed. Once a Construction Service Agreement (CSA) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted. Of the 2,449 projects withdrawn, 482 (19.7 percent) were withdrawn after the completion of a Construction Service Agreement.

Table 12-16 Last milestone at time of withdrawal: January 1997 through March 2019

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	402	16.4%	96	875
Feasibility Study	792	32.3%	273	1,633
System Impact Study	490	20.0%	753	3,248
Facilities Study	283	11.6%	1,071	3,454
Construction Service Agreement (CSA) or beyond	482	19.7%	1,299	4,249
Total	2,449	100.0%		

35 See PJM, "Manual 14B: PJM Region Transmission Planning Process," Rev. 42 (Aug. 23, 2018).

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): March 31, 2019[36]

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 1,050 projects in the queue as of March 31, 2019, 267 (25.4 percent) had a completed feasibility study and 273 (26.0 percent) had a completed construction service agreement.

Table 12-18 Project queue times by milestone (days): March 31, 2019

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	291	27.7%	106	550
Feasibility Study	267	25.4%	440	1,529
System Impact Study	190	18.1%	834	2,342
Facilities Study	29	2.8%	1,571	3,836
Construction Service Agreement (CSA) or beyond	273	26.0%	1,534	5,298
Total	1,050	100.0%		

36 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.

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 (SIS), facilities study agreement (FSA) and construction service agreement (CSA) milestones as well as the historic completion rates for all projects including those withdrawn before reaching the SIS milestone. For each unit type, the total MW in service was divided by the total energy MW entered in the queue. To calculate the completion rates for projects that reached the individual milestones, only those projects that reached a final status of withdrawn or in service were evaluated. For example, if a project was withdrawn after the completion of its SIS, but before the completion of the FSA, the totals would be included in the calculation of the SIS completion rate, but not in the calculation of the FSA or CSA completion rates. Similarly, if a project was withdrawn after the completion of its FSA, but before the completion of the CSA, the totals would be included in the calculation of the SIS and FSA completion rates, but not in the calculation of the CSA completion rate. The completion rates show that of all wind projects to ever enter the queue and complete the system impact study stage, 16.7 percent of the queued MW have gone into service. The completion rate for wind projects increases to 31.4 percent when wind projects complete the facility study agreement, and further increases to 49.9 percent when wind projects complete the construction service agreement. Of all wind projects to enter the queue, only 7.9 percent of the queued MW have gone into service.

Table 12-19 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: January 1997 through March 2019

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)	Completion Rate (ALL)
Battery	27.6%	46.0%	58.3%	7.3%
CC	32.8%	52.1%	86.6%	12.7%
CT - Natural Gas	77.6%	83.6%	87.8%	50.0%
CT - Oil	35.6%	60.2%	90.8%	25.1%
CT - Other	12.3%	18.7%	29.6%	10.7%
Fuel Cell	6.6%	6.8%	6.8%	5.0%
Hydro - Pumped Storage	100.0%	100.0%	100.0%	20.6%
Hydro - Run of River	40.8%	56.9%	62.3%	21.5%
Nuclear	34.8%	41.7%	51.1%	28.6%
RICE - Natural Gas	33.0%	47.0%	54.2%	21.0%
RICE - Oil	30.6%	55.9%	55.9%	22.4%
RICE - Other	90.0%	91.7%	92.4%	77.9%
Solar	14.7%	28.3%	36.0%	2.0%
Steam - Coal	13.3%	24.9%	37.0%	6.0%
Steam - Natural Gas	90.1%	90.1%	90.1%	81.4%
Steam - Oil	0.0%	0.0%	0.0%	0.0%
Steam - Other	27.9%	37.2%	45.2%	23.5%
Wind	16.7%	31.4%	49.9%	7.9%

On March 31, 2019, 124,143.0 MW of capacity were in generation request queues in the status of active, under construction or suspended. Of the total 124,143.0 MW in the queue, 56,255.2 MW (45.3 percent) have reached at least the SIS milestone and 67,887.8 MW (54.7 percent) have not received a completed SIS. Based on historical completion rates, (applying the unit type specific completion rates for those projects that have reached the SIS, FSA or CSA milestone, and using the overall completion rates for those projects that have not yet reached the SIS milestone), 34,184 MW of new generation in the queue are expected to go into service.

Queue Analysis by Fuel Group

The time it takes to complete a study depends on the backlog and the number of projects in the queue, but not on the size of the project. Table 12-20 shows the number of projects that entered the queue by year and by fuel group. The fuel groups are nuclear units, renewable units (including solar, hydro, storage, biomass and wind) and traditional units (all other fuels). The number of queue entries has increased during the past several years, primarily by renewable projects. Of the 1,682 projects entered from January 2015 through March 2019, 1,378 projects, 81.9 percent, were renewable. Of the 179 projects entered in the first three months of 2019, 171 projects, 95.5 percent, were renewable.

Table 12-20 Number of projects entered in the queue: March 31, 2019

	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	391	48	440
2019	0	171	8	179
Total	70	2,792	1,472	4,334

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 59.1 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: March 31, 2019

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	9	0.9%	167.5	0.1%
Renewable	859	81.8%	73,349.2	59.1%
Traditional	182	17.3%	50,626.4	40.8%
Total	1,050	100.0%	124,143.0	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 March 31, 2019. As of March 31, 2019, 4,334 projects, representing 548,811.2 MW, have entered the queue process since its inception. Of those, 835 projects, representing 65,091.8 MW, went into service. Of the projects that entered the queue process, 2,449 projects, representing 359,576.4 MW (65.5 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

A total of 3,538 projects have been classified as new generation and 796 projects have been classified as upgrades. Wind, solar and natural gas projects have accounted for 3,463 projects, or 79.9 percent, of all 4,334 generation queue projects.

Table 12-22 Status of all generation queue projects: January 1997 through March 2019

		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	21	58	48	10	24	3	0	11	2	8	0	55	133	8	5	0	3	79	468
	Upgrade	4	82	90	15	5	0	3	16	41	8	1	14	16	52	7	0	7	6	367
Under Construction	New Generation	21	4	1	0	1	0	0	2	0	2	0	0	16	0	0	0	0	9	56
	Upgrade	1	13	2	0	0	0	0	0	1	0	0	1	3	2	0	0	1	4	28
Suspended	New Generation	7	5	1	0	0	0	0	0	0	3	0	0	27	0	0	0	1	9	53
	Upgrade	2	5	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	10
Withdrawn	New Generation	101	407	19	9	81	26	2	39	9	21	12	15	989	55	1	0	34	412	2,232
	Upgrade	16	84	6	13	13	2	0	4	9	0	2	2	28	14	0	0	2	22	217
Active	New Generation	39	41	13	1	0	0	2	1	1	5	0	1	537	0	0	0	0	88	729
	Upgrade	14	36	30	0	0	0	0	2	7	1	1	2	56	4	3	0	1	17	174
Total Projects	New Generation	189	515	82	20	106	29	4	53	12	39	12	71	1,702	63	6	0	38	597	3,538
	Upgrade	37	220	129	28	18	2	3	22	58	9	4	19	104	72	10	0	11	50	796

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, 72.7 percent of all hydro run of river projects classified as upgrades are currently in service in PJM, 18.2 percent of hydro run of river upgrades were withdrawn and 9.1 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 March 2019

		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	11.1%	11.3%	58.5%	50.0%	22.6%	10.3%	0.0%	20.8%	16.7%	20.5%	0.0%	77.5%	7.8%	12.7%	83.3%	0.0%	7.9%	13.2%	13.2%
	Upgrade	10.8%	37.3%	69.8%	53.6%	27.8%	0.0%	100.0%	72.7%	70.7%	88.9%	25.0%	73.7%	15.4%	72.2%	70.0%	0.0%	63.6%	12.0%	46.1%
Under Construction	New Generation	11.1%	0.8%	1.2%	0.0%	0.9%	0.0%	0.0%	3.8%	0.0%	5.1%	0.0%	0.0%	0.9%	0.0%	0.0%	0.0%	0.0%	1.5%	1.6%
	Upgrade	2.7%	5.9%	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%	1.7%	0.0%	0.0%	5.3%	2.9%	2.8%	0.0%	0.0%	9.1%	8.0%	3.5%
Suspended	New Generation	3.7%	1.0%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.7%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%	2.6%	1.5%	1.5%
	Upgrade	5.4%	2.3%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	0.0%	0.0%	0.0%	0.0%	2.0%	1.3%
Withdrawn	New Generation	53.4%	79.0%	23.2%	45.0%	76.4%	89.7%	50.0%	73.6%	75.0%	53.8%	100.0%	21.1%	58.1%	87.3%	16.7%	0.0%	89.5%	69.0%	63.1%
	Upgrade	43.2%	38.2%	4.7%	46.4%	72.2%	100.0%	0.0%	18.2%	15.5%	0.0%	50.0%	10.5%	26.9%	19.4%	0.0%	0.0%	18.2%	44.0%	27.3%
Active	New Generation	20.6%	8.0%	15.9%	5.0%	0.0%	0.0%	50.0%	1.9%	8.3%	12.8%	0.0%	1.4%	31.6%	0.0%	0.0%	0.0%	0.0%	14.7%	20.6%
	Upgrade	37.8%	16.4%	23.3%	0.0%	0.0%	0.0%	0.0%	9.1%	12.1%	11.1%	25.0%	10.5%	53.8%	5.6%	30.0%	0.0%	9.1%	34.0%	21.9%

Table 12-24 shows the nameplate generating capacity of projects in the PJM generation queue by technology type and project classification. For example, the 412 new generation wind projects that have been withdrawn from the queue as of March 31, 2019, (as shown in Table 12-22) constitute 69,371.0 MW of nameplate capacity. The 491 new generation and upgrade combined cycle projects that have been withdrawn in the same time period constitute 205,820.3 MW of nameplate capacity.

Table 12-24 Status of all generation capacity (MW) in the PJM generation queue: January 1997 through March 2019

		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	216.9	30,660.5	6,600.5	676.5	148.2	1.9	0.0	471.5	1,639.0	118.2	0.0	440.1	1,445.0	1,343.0	723.0	0.0	60.0	7,762.2	52,306.5
	Upgrade	42.4	5,491.8	2,323.5	127.8	12.3	0.0	390.0	373.6	2,282.8	15.7	23.3	49.9	17.4	897.5	131.5	0.0	605.3	0.5	12,785.3
Under Construction	New Generation	24.6	2,520.0	205.0	0.0	3.2	0.0	0.0	22.7	0.0	21.2	0.0	0.0	358.9	0.0	0.0	0.0	0.0	1,558.5	4,714.1
	Upgrade	0.0	855.1	48.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	13.9	48.0	0.0	0.0	62.5	239.5	1,311.0
Suspended	New Generation	43.3	4,119.0	19.9	0.0	0.0	0.0	0.0	0.0	0.0	59.7	0.0	0.0	398.3	0.0	0.0	0.0	16.0	1,289.7	5,945.9
	Upgrade	23.0	650.1	200.0	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	16.3	909.4
Withdrawn	New Generation	1,273.7	195,582.1	2,020.4	1,721.0	1,244.2	5.5	500.0	1,986.9	8,161.0	348.2	63.9	86.6	27,580.0	33,511.6	27.0	0.0	1,035.8	69,371.0	344,518.8
	Upgrade	354.1	10,238.3	431.5	589.0	72.5	0.9	0.0	57.1	916.0	0.0	13.0	6.0	835.1	865.0	0.0	0.0	37.1	642.0	15,057.6
Active	New Generation	1,229.9	32,051.3	3,298.9	14.0	0.0	0.0	1,000.0	15.0	28.0	90.3	0.0	2.0	37,565.4	0.0	0.0	0.0	0.0	25,935.8	101,230.6
	Upgrade	341.0	4,811.8	1,301.0	0.0	0.0	0.0	0.0	5.5	95.5	1.6	4.0	4.8	1,887.5	85.0	94.0	0.0	40.0	1,360.5	10,032.1
Total Projects	New Generation	2,788.3	264,932.9	12,144.7	2,411.5	1,395.6	7.4	1,500.0	2,496.1	9,828.0	637.6	63.9	528.7	67,347.6	34,854.6	750.0	0.0	1,111.8	105,917.2	508,715.8
	Upgrade	760.5	22,047.1	4,304.0	716.8	84.8	0.9	390.0	436.2	3,338.3	17.3	40.3	60.7	2,773.9	1,895.5	225.5	0.0	744.9	2,258.8	40,095.4

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, 65.5 percent of wind project MW classified as new generation have been withdrawn from the queue between January 1, 1997, and March 31, 2019.

Table 12-25 Status of all generation queue projects as percent of total MW in project classification: January 1997 through March 2019

		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	7.8%	11.6%	54.3%	28.1%	10.6%	26.2%	0.0%	18.9%	16.7%	18.5%	0.0%	83.2%	2.1%	3.9%	96.4%	0.0%	5.4%	7.3%	10.3%
	Upgrade	5.6%	24.9%	54.0%	17.8%	14.5%	0.0%	100.0%	85.6%	68.4%	90.8%	57.8%	82.2%	0.6%	47.3%	58.3%	0.0%	81.3%	0.0%	31.9%
Under Construction	New Generation	0.9%	1.0%	1.7%	0.0%	0.2%	0.0%	0.0%	0.9%	0.0%	3.3%	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%	1.5%	0.9%
	Upgrade	0.0%	3.9%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	0.5%	2.5%	0.0%	0.0%	8.4%	10.6%	3.3%
Suspended	New Generation	1.6%	1.6%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	9.4%	0.0%	0.0%	0.6%	0.0%	0.0%	0.0%	1.4%	1.2%	1.2%
	Upgrade	3.0%	2.9%	4.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.7%	2.3%
Withdrawn	New Generation	45.7%	73.8%	16.6%	71.4%	89.2%	73.8%	33.3%	79.6%	83.0%	54.6%	100.0%	16.4%	41.0%	96.1%	3.6%	0.0%	93.2%	65.5%	67.7%
	Upgrade	46.6%	46.4%	10.0%	82.2%	85.5%	100.0%	0.0%	13.1%	27.4%	0.0%	32.3%	9.9%	30.1%	45.6%	0.0%	0.0%	5.0%	28.4%	37.6%
Active	New Generation	44.1%	12.1%	27.2%	0.6%	0.0%	0.0%	66.7%	0.6%	0.3%	14.2%	0.0%	0.4%	55.8%	0.0%	0.0%	0.0%	0.0%	24.5%	19.9%
	Upgrade	44.8%	21.8%	30.2%	0.0%	0.0%	0.0%	0.0%	1.3%	2.9%	9.2%	9.9%	7.9%	68.0%	4.5%	41.7%	0.0%	5.4%	60.2%	25.0%

Table 12-26 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 93.4 percent of all new projects entering the generation queue have been either combined cycle (26.7 percent), wind (23.4 percent) or solar projects (43.3 percent).

Table 12-26 Queue project MW by unit type and queue entry year: January 1997 through March 2019

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	997.0	4,122.7
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	1,614.7	8,488.1
2005	0.0	5,824.6	961.0	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	20,364.9
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	13,944.6	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	43,794.4
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	284.6	1,837.0	0.0	0.0	143.1	1,529.8	22,746.8
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	11,704.5	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	19,028.8
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	5,465.8	702.0	0.0	4.1	2.7	0.0	20.5	39.1	97.1	0.0	33.8	13,892.4	14.0	17.0	0.0	0.0	5,452.0	25,765.2
2018	1,467.2	9,792.4	2,652.4	14.0	0.0	0.0	1,000.0	0.0	28.1	0.0	0.0	0.8	24,723.5	29.0	0.0	0.0	40.0	18,209.3	57,956.7
2019	540.6	2,194.0	0.0	0.0	0.0	0.0	500.0	0.0	0.0	0.0	0.0	0.0	8,421.4	0.0	0.0	0.0	0.0	4,733.3	16,389.3
Total	3,548.8	286,980.0	16,448.7	3,128.3	1,480.3	8.3	1,890.0	2,932.3	13,166.3	654.9	104.2	589.4	70,121.4	36,750.1	975.5	0.0	1,856.7	108,176.0	548,811.2

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 March 31, 2019, by zone. Of the 104 combined cycle projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 48 projects (46.2 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 March 2019

	Number of Projects																						
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	1	4	2	2	2	1	0	2	0	7	2	0	7	3	0	5	1	4	10	5	0	58
	Upgrade	2	8	7	3	0	3	0	0	0	14	5	0	5	1	0	10	3	2	5	14	0	82
Under Construction	New Generation	1	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1	0	0	1	0	4
	Upgrade	0	2	0	1	0	1	0	0	0	0	0	0	1	1	0	2	1	2	2	0	0	13
Suspended	New Generation	0	1	1	0	0	0	0	0	0	1	0	0	1	0	0	0	0	1	0	0	0	5
	Upgrade	0	0	0	0	0	0	0	0	0	0	1	0	2	0	0	0	0	2	0	0	0	5
Withdrawn	New Generation	21	18	40	12	8	11	0	1	2	17	17	3	24	25	0	43	39	33	39	52	2	407
	Upgrade	7	7	5	3	0	3	0	1	0	10	4	0	5	7	0	3	5	3	6	15	0	84
Active	New Generation	1	8	9	5	0	7	1	0	0	1	0	0	1	0	0	0	2	0	2	4	0	41
	Upgrade	2	6	8	2	0	5	0	0	0	3	0	0	1	2	0	1	2	0	3	1	0	36
Total Projects	New Generation	24	31	52	19	10	19	1	3	2	26	19	3	33	29	0	48	43	38	51	62	2	515
	Upgrade	11	23	20	9	0	12	0	1	0	27	10	0	14	11	0	16	11	9	16	30	0	220

Table 12-28 shows the status of all combined cycle projects by MW that entered PJM generation queues from January 1, 1997 through March 31, 2019, by zone. Of the 45,007.3 MW of combined cycle projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 23,354.9 MW (51.9 percent) are located within AEP, ComEd and APS.

Table 12-28 Status of all combined cycle queue projects by zone (MW): January 1997 through March 2019

	Project MW																						
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	650.0	3,032.0	1,455.0	1,599.0	140.0	600.0	0.0	533.0	0.0	5,854.1	319.2	0.0	1,665.8	2,107.0	0.0	2,665.0	850.0	1,560.0	5,750.0	1,880.5	0.0	30,660.5
	Upgrade	220.0	230.0	790.0	306.0	0.0	621.0	0.0	0.0	0.0	873.0	102.0	0.0	110.0	10.0	0.0	973.5	92.3	89.1	229.0	845.9	0.0	5,491.8
Under Construction	New Generation	452.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	450.0	0.0	0.0	1,050.0	0.0	0.0	568.0	0.0	2,520.0
	Upgrade	0.0	100.0	0.0	0.0	0.0	12.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.0	0.0	35.0	50.0	139.5	483.0	0.0	0.0	855.1
Suspended	New Generation	0.0	585.0	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,060.0	0.0	0.0	440.0	0.0	0.0	0.0	0.0	894.0	0.0	0.0	0.0	4,119.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	451.0	0.0	55.0	0.0	0.0	0.0	0.0	144.1	0.0	0.0	0.0	650.1
Withdrawn	New Generation	7,515.4	11,249.5	16,982.1	7,471.0	3,122.1	6,225.3	0.0	134.5	665.0	11,261.0	5,436.4	991.8	12,552.6	13,001.0	0.0	23,340.0	15,931.0	20,414.2	16,785.7	22,496.7	6.9	195,582.1
	Upgrade	124.4	711.0	579.0	86.0	0.0	1,375.0	0.0	36.0	0.0	580.4	668.0	0.0	253.0	1,742.0	0.0	240.0	1,040.6	85.0	500.0	2,217.9	0.0	10,238.3
Active	New Generation	575.0	6,589.0	6,606.0	5,217.0	0.0	4,954.9	1,150.0	0.0	0.0	1,600.0	0.0	0.0	570.0	0.0	0.0	0.0	183.0	0.0	1,515.0	3,091.4	0.0	32,051.3
	Upgrade	41.6	742.0	883.7	588.0	0.0	1,741.7	0.0	0.0	0.0	180.0	0.0	0.0	110.0	113.9	0.0	67.0	85.0	0.0	207.8	51.1	0.0	4,811.8
Total Projects	New Generation	9,192.4	21,455.5	26,183.1	14,287.0	3,262.1	11,780.2	1,150.0	667.5	665.0	19,775.1	5,755.6	991.8	15,228.4	15,558.0	0.0	26,005.0	18,014.0	22,868.2	24,050.7	28,036.6	6.9	264,932.9
	Upgrade	386.0	1,783.0	2,252.7	980.0	0.0	3,750.3	0.0	36.0	0.0	1,633.4	1,221.0	0.0	528.0	1,900.9	0.0	1,315.5	1,267.9	457.7	1,419.8	3,114.9	0.0	22,047.1

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 March 31, 2019, by zone. Of the 48 combustion turbine natural gas projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 25 projects (52.1 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 March 2019

		Number of Projects																					
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	5	0	6	0	3	0	0	0	0	2	7	0	3	1	0	2	4	2	4	9	0	48
	Upgrade	4	7	6	1	0	9	6	0	0	24	7	0	0	1	0	2	2	3	4	14	0	90
Under Construction	New Generation	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	0	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	2
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	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	0	1
Withdrawn	New Generation	1	4	0	0	0	1	0	0	0	2	0	0	0	0	0	1	4	0	1	5	0	19
	Upgrade	2	1	0	1	0	0	0	0	0	0	0	0	0	1	0	0	1	0	0	0	0	6
Active	New Generation	1	2	0	0	2	2	0	0	0	3	0	1	0	0	0	1	1	0	0	0	0	13
	Upgrade	0	2	5	1	0	13	0	0	0	6	1	0	0	0	0	1	1	0	0	0	0	30
Total Projects	New Generation	7	6	6	0	5	3	0	0	1	7	7	1	3	1	0	4	10	2	5	14	0	82
	Upgrade	6	10	11	3	0	23	6	0	0	30	8	0	2	2	0	3	4	3	4	14	0	129

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 March 31, 2019, by zone. Of the 5,072.8 MW of combustion turbine natural gas projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 2,455.0 MW (48.4 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 March 2019

		Project MW																					
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	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	10.0	0.0	559.0	361.9	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	86.0	0.0	0.0	34.1	0.0	13.0	25.0	32.0	252.3	215.0	0.0	2,323.5
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	0.0	205.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	48.0	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	48.0
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	0.0	19.9	0.0	0.0	0.0	0.0	19.9
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0
Withdrawn	New Generation	7.5	460.0	0.0	0.0	0.0	10.0	0.0	0.0	0.0	75.5	0.0	0.0	0.0	0.0	0.0	0.5	306.9	0.0	19.9	1,140.1	0.0	2,020.4
	Upgrade	165.5	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	0.0	235.0	0.0	0.0	0.0	0.0	431.5
Active	New Generation	230.0	1,059.0	0.0	0.0	153.6	230.0	0.0	0.0	0.0	1,061.3	0.0	73.0	0.0	0.0	0.0	29.0	463.0	0.0	0.0	0.0	0.0	3,298.9
	Upgrade	0.0	38.0	120.0	70.0	0.0	960.0	0.0	0.0	0.0	95.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	1,301.0
Total Projects	New Generation	598.2	1,519.0	1,176.0	0.0	176.6	240.0	0.0	0.0	205.0	2,151.8	1,491.0	73.0	522.1	10.0	0.0	588.5	1,151.7	5.0	170.8	2,066.0	0.0	12,144.7
	Upgrade	209.2	234.0	307.7	135.0	0.0	1,265.0	60.0	0.0	0.0	982.7	86.0	0.0	200.0	34.1	0.0	13.0	278.0	32.0	252.3	215.0	0.0	4,304.0

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 March 31, 2019, by zone. Of the 85 wind projects to achieve in service status, 49 projects (57.6 percent) are located within AEP, ComEd and APS. Of the 128 wind projects currently active, suspended or under construction in the PJM generation queue, 90 projects (70.3 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 March 2019

		Number of Projects																					
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	1	14	14	0	0	19	0	0	0	1	0	0	0	0	0	0	22	0	8	0	0	79
	Upgrade	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	4	0	0	0	0	6
Under Construction	New Generation	0	1	2	0	0	3	0	0	0	2	0	0	0	0	0	0	1	0	0	0	0	9
	Upgrade	0	0	1	0	0	2	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	4
Suspended	New Generation	0	4	2	0	0	0	0	0	0	1	0	0	0	0	0	0	1	0	1	0	0	9
	Upgrade	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Withdrawn	New Generation	16	98	41	8	0	96	14	0	0	21	10	1	0	0	0	0	63	0	43	1	0	412
	Upgrade	2	1	6	0	0	3	0	0	0	2	0	0	0	0	0	0	6	0	2	0	0	22
Active	New Generation	6	23	6	3	0	30	1	0	0	4	3	0	7	0	0	0	0	0	5	0	0	88
	Upgrade	0	2	4	0	0	9	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	17
Total Projects	New Generation	23	140	65	11	0	148	15	0	0	29	13	1	7	0	0	0	87	0	57	1	0	597
	Upgrade	2	3	12	0	0	16	0	0	0	3	0	0	0	0	0	0	12	0	2	0	0	50

Table 12-32 shows the status of all wind projects by MW that entered PJM generation queues from January 1, 1997 through March 31, 2019, by zone. Of the 7,762.7 MW of wind generation capacity to achieve the in service status, 6,430.7 MW (82.8 percent) of nameplate capacity is located within AEP, ComEd and APS. Of the 30,400.3 MW of wind generation capacity currently active, suspended or under construction in the PJM generation queue, 16,337.8 MW of generation capacity (53.7 percent) is located within AEP, ComEd and APS.

Table 12-32 Status of all wind generation queue projects by zone (MW): January 1997 through March 2019

		Project MW																					
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	7.5	2,738.7	1,004.0	0.0	0.0	2,688.0	0.0	0.0	0.0	102.5	0.0	0.0	0.0	0.0	0.0	0.0	995.0	0.0	226.5	0.0	0.0	7,762.2
	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	0.5	0.0	0.0	0.0	0.0	0.5
Under Construction	New Generation	0.0	150.0	260.0	0.0	0.0	766.5	0.0	0.0	0.0	312.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	1,558.5
	Upgrade	0.0	0.0	0.0	0.0	0.0	207.5	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	0.0	239.5
Suspended	New Generation	0.0	722.0	293.1	0.0	0.0	0.0	0.0	0.0	0.0	76.6	0.0	0.0	0.0	0.0	0.0	0.0	100.0	0.0	98.0	0.0	0.0	1,289.7
	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	0.0	16.3
Withdrawn	New Generation	3,646.4	20,153.2	3,134.1	1,295.6	0.0	22,619.2	2,028.0	0.0	0.0	4,988.4	2,816.8	150.3	0.0	0.0	0.0	0.0	5,277.0	0.0	3,242.1	20.0	0.0	69,371.0
	Upgrade	5.0	200.0	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	0.0	243.4	0.0	6.0	0.0	0.0	642.0
Active	New Generation	2,803.6	4,867.3	439.6	816.1	0.0	7,375.5	100.0	0.0	0.0	2,700.6	599.8	0.0	5,943.2	0.0	0.0	0.0	0.0	0.0	290.3	0.0	0.0	25,935.8
	Upgrade	0.0	270.0	94.4	0.0	0.0	875.7	0.0	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	1,360.5
Total Projects	New Generation	6,457.5	28,631.2	5,130.8	2,111.7	0.0	33,449.1	2,128.0	0.0	0.0	8,180.1	3,416.6	150.3	5,943.2	0.0	0.0	0.0	6,442.0	0.0	3,856.9	20.0	0.0	105,917.2
	Upgrade	5.0	470.0	210.7	0.0	0.0	1,088.9	0.0	0.0	0.0	114.0	0.0	0.0	0.0	0.0	0.0	0.0	364.2	0.0	6.0	0.0	0.0	2,258.8

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 March 31, 2019, by zone. Of the 149 solar projects to achieve in service status, 9 projects (6.0 percent) are located within AEP, ComEd and APS. Of the 640 solar projects currently active, suspended or under construction in the PJM generation queue, 185 projects (28.9 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 March 2019

		Number of Projects																				
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	7	4	4	0	1	1	1	0	0	21	10	0	42	0	0	1	0	0	2	39	0	133
	Upgrade	0	0	0	0	0	0	0	0	0	2	8	0	6	0	0	0	0	0	0	0	0	16
Under Construction	New Generation	0	0	1	0	0	0	0	0	0	4	2	0	3	0	0	0	0	0	0	6	0	16
	Upgrade	0	0	0	0	0	0	0	0	0	2	1	0	0	0	0	0	0	0	0	0	0	3
Suspended	New Generation	0	5	15	0	0	0	1	0	0	0	0	0	3	2	0	0	0	0	0	1	0	27
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1
Withdrawn	New Generation	161	87	62	9	12	30	14	12	0	159	119	4	171	13	0	6	13	18	28	71	0	989
	Upgrade	2	2	1	0	0	2	0	0	0	11	1	0	8	0	0	0	0	0	0	1	0	28
Active	New Generation	26	94	35	12	1	25	11	3	4	174	40	13	19	14	0	1	17	8	15	24	1	537
	Upgrade	1	7	1	1	0	2	1	3	1	26	2	1	2	1	0	0	0	1	3	2	1	56
Total Projects	New Generation	194	190	117	21	14	56	27	15	4	358	171	17	238	29	0	8	30	26	45	141	1	1,702
	Upgrade	3	9	2	1	0	4	1	3	1	41	12	1	16	2	0	0	0	1	3	3	1	104

Table 12-34 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997 through March 31, 2019, by zone. Of the 1,462.4 MW of solar generation capacity to achieve in service status, 76.7 MW (5.2 percent) of nameplate capacity is located within AEP, ComEd and APS. Of the 40,244.0 MW of solar generation capacity currently active, suspended or under construction in the PJM generation queue, 15,919.8 MW of generation capacity (39.6 percent) is located within AEP, ComEd and APS.

Table 12-34 Status of all solar generation queue projects by zone (MW): January 1997 through March 2019

		Project MW																				
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	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	675.9	124.4	0.0	295.3	0.0	0.0	3.3	0.0	0.0	15.0	193.5	0.0	1,445.0
	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	14.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.4
Under Construction	New Generation	0.0	0.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	240.9	26.0	0.0	51.9	0.0	0.0	0.0	0.0	0.0	0.0	30.1	0.0	358.9
	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	0.0	13.9
Suspended	New Generation	0.0	60.0	266.3	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	8.0	38.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0	398.3
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0
Withdrawn	New Generation	1,712.3	6,607.8	1,586.7	271.1	53.3	1,816.8	523.9	279.4	0.0	9,725.9	1,561.2	309.9	1,373.6	487.0	0.0	51.4	171.7	184.5	383.7	479.7	0.0	27,580.0
	Upgrade	10.0	106.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	674.0	0.0	0.0	23.8	0.0	0.0	0.0	0.0	0.0	0.0	1.3	0.0	835.1
Active	New Generation	456.4	10,647.4	1,500.5	1,299.0	4.0	2,863.5	1,097.0	295.0	71.7	14,280.9	1,476.7	1,332.0	115.8	601.6	0.0	18.0	770.9	116.5	476.2	102.3	40.0	37,565.4
	Upgrade	0.0	427.0	75.0	20.0	0.0	70.0	20.0	85.0	8.3	936.9	40.0	80.0	17.3	20.0	0.0	0.0	0.0	3.6	60.0	4.4	20.0	1,887.5
Total Projects	New Generation	2,226.0	17,330.0	3,416.6	1,570.1	58.4	4,689.3	1,643.4	574.4	71.7	24,923.6	3,188.3	1,641.9	1,844.6	1,126.6	0.0	72.7	942.6	301.0	874.9	811.7	40.0	67,347.6
	Upgrade	10.0	533.0	75.0	20.0	0.0	90.0	20.0	85.0	8.3	1,627.9	40.0	80.0	55.4	40.0	0.0	0.0	0.0	3.6	60.0	5.7	20.0	2,773.9

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."[37] 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 March 31, 2019, 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 548,811.2 MW that have entered the queue during the time period of January 1, 1997, through March 31, 2019, 62,303.5 MW (11.4 percent) have been submitted by Transmission Owners building in their own service territory. PSEG is the Transmission Owner with the highest percentage of affiliates building in their own service territory. Of the 36,453.1 MW that entered the queue during the time period of January 1, 1997, through March 31, 2019, 14,287.9 MW (39.2 percent) have been submitted by PSEG or one of their affiliated companies.

37 See OATT § 1 (Transmission Owner).

Table 12-35 Relationship between project developer and Transmission Owner for all interconnection queue projects MW by unit type: March 31, 2019

				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	48	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	513	711.0	22,558.5	1,753.0	7.5	127.3	0.0	0.0	448.4	0.0	12.0	0.0	75.4	17,720.3	10,368.0	0.0	0.0	492.0	29,101.2	83,374.5
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	1,641.9	0.0	0.0	0.0	0.0	2,128.0	4,993.7
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	25	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	80.0	2,810.0	0.0	0.0	0.0	0.0	5,824.2
Dominion	Dominion	Related	98	0.0	12,364.0	908.7	100.0	0.0	0.0	340.0	0.0	1,944.0	0.0	0.0	60.0	1,056.5	301.0	0.0	0.0	4.0	146.0	17,224.2
		Unrelated	510	395.6	9,044.5	2,225.8	0.5	227.3	0.0	0.0	35.0	0.0	0.0	10.0	119.4	25,495.0	20.0	0.0	0.0	316.3	8,148.1	46,037.6
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	26	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	21	0.0	170.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,721.9	0.0	0.0	0.0	0.0	150.3	2,115.2
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	304	141.0	8,848.4	807.4	380.0	20.7	2.8	0.0	0.0	0.0	2.0	5.0	10.3	2,227.7	15.0	5.5	0.0	10.0	6,462.5	18,938.3
	BGE	Related	14	20.0	250.0	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	528.0
		Unrelated	58	40.6	3,012.1	166.6	18.0	133.0	0.0	0.0	0.4	3,280.0	1.3	0.0	0.0	38.4	0.0	2.5	0.0	25.0	0.0	6,717.9
	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	345	463.1	15,530.5	1,505.0	42.0	65.2	0.0	0.0	22.7	0.0	35.0	0.0	67.7	4,770.3	1,926.0	91.0	0.0	90.0	34,538.0	59,146.4
	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	286	143.0	5,611.6	1,226.0	600.9	42.6	0.0	0.0	0.0	0.0	0.0	0.0	84.6	3,220.9	653.0	15.0	0.0	65.0	3,416.6	15,079.2
	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	80	5.3	20,355.5	596.5	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	21,067.7
	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	90	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	304.6	0.0	0.0	0.0	0.0	0.0	25,402.0
FirstEnergy	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	374	330.9	26,982.8	1,483.7	0.0	84.4	0.0	0.0	623.3	0.0	140.0	53.8	25.4	3,491.6	4,092.0	0.0	0.0	184.4	5,341.5	42,833.7
	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	80	56.1	13,589.0	135.0	5.0	166.4	0.0	0.0	0.0	0.0	59.7	0.0	6.9	1,590.1	0.0	16.5	0.0	0.0	2,111.7	17,736.4
	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	365	382.8	15,756.4	722.1	0.0	4.8	0.6	0.0	1.6	0.0	0.6	0.0	12.8	1,888.0	0.0	0.0	0.0	30.0	5,943.2	24,742.8
	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	105	23.0	17,458.9	44.1	1,196.9	52.1	0.0	0.0	0.0	93.0	0.0	8.0	23.2	1,166.6	0.0	0.0	0.0	84.0	0.0	20,149.8
	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	255	97.4	18,747.9	1,424.7	0.0	214.4	0.0	16.0	46.3	0.0	341.8	8.0	14.8	942.6	561.0	590.0	0.0	525.0	6,806.2	30,335.9
OVEC	OVEC	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	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
PPL	PPL	Related	21	0.0	2,261.0	0.0	0.0	0.0	0.0	0.0	109.0	1,600.0	0.0	0.0	0.0	19.8	111.0	0.0	0.0	0.0	0.0	4,100.8
		Unrelated	246	528.8	23,209.5	423.1	8.0	234.5	0.0	1,500.0	142.6	388.0	19.9	2.4	44.7	915.1	6,896.6	0.0	0.0	31.0	3,862.9	38,207.1
PSEG	PSEG	Related	109	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	184.7	24.0	44.0	0.0	0.0	0.0	14,287.9
		Unrelated	209	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	632.7	0.0	20.0	0.0	0.0	20.0	22,165.2
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	4	0.0	6.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	60.0	0.0	0.0	0.0	0.0	0.0	66.9
Total		Related	389	119.8	40,973.9	3,135.8	189.5	0.0	0.0	374.0	394.0	5,886.3	0.0	0.0	68.5	1,488.2	9,288.5	235.0	0.0	4.0	146.0	62,303.5
		Unrelated	3945	3,429.0	246,006.1	13,312.9	2,938.8	1,480.3	8.3	1,516.0	2,538.3	7,280.0	654.9	104.2	520.9	68,633.2	27,461.6	740.5	0.0	1,852.7	108,030.0	486,507.7

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 March 31, 2019, by transmission owner and project status. Of the 39,527.4 combined cycle project MW that have achieved in service or under construction status during this time period, 9,156.0 MW (23.2 percent) have been developed by Transmission Owners building in their own service territory. EKPC is the Transmission Owner with the highest percentage of affiliates building combined cycle projects in their own service territory. Of the 991.8 MW that entered the queue during the time period of January 1, 1997, through March 31, 2019, 821.8 MW (82.9 percent) have been submitted by EKPC or one of their affiliated companies.

Table 12-36 Relationship between project developer and transmission owner for all combined cycle project MW in PJM interconnection queue: March 31, 2019

			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	7,231.0	2,682.0	100.0	585.0	11,960.5	22,558.5
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	2,300.0	0.0	0.0	0.0	0.0	2,300.0
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	90.0	4,773.0	0.0	0.0	7,501.0	12,364.0
		Unrelated	1,690.0	1,954.1	0.0	1,060.0	4,340.4	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	616.6	870.0	452.0	0.0	6,909.8	8,848.4
	BGE	Related	0.0	130.0	0.0	0.0	120.0	250.0
		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	6,696.6	1,221.0	12.6	0.0	7,600.3	15,530.5
	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	3,638.5	35.0	0.0	16,615.0	20,355.5
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	1,649.1	139.5	1,038.1	20,499.2	23,325.9
FirstEnergy	APS	Related	0.0	525.0	0.0	0.0	928.0	1,453.0
		Unrelated	7,489.7	1,720.0	0.0	1,140.0	16,633.1	26,982.8
	ATSI	Related	0.0	0.0	0.0	0.0	1,678.0	1,678.0
		Unrelated	5,805.0	1,905.0	0.0	0.0	5,879.0	13,589.0
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	680.0	1,775.8	0.0	495.0	12,805.6	15,756.4
	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	268.0	942.3	1,100.0	0.0	16,437.6	18,747.9
OVEC	OVEC	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
PPL	PPL	Related	0.0	600.0	0.0	0.0	1,661.0	2,261.0
		Unrelated	1,722.8	5,379.0	483.0	0.0	15,624.7	23,209.5
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	241.1	8,588.0	568.0	0.0	31,576.8	40,973.9
		Unrelated	37,772.0	27,564.3	2,807.1	4,769.1	174,243.5	247,156.1

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 March 31, 2019, by transmission owner and project status. Of the 9,177.0 CT – natural gas project MW that have achieved in service or under construction status during this time period, 2,107.0 (23.0 percent) have been developed by Transmission Owners building in their own service territory. PSEG is the Transmission Owner with the highest percentage of affiliates building CT – natural gas projects in their own service territory. Of the 2,281.0 MW that entered the queue during the time period of January 1, 1997, through March 31, 2019, 1,818.1 MW (79.7 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-37 Relationship between project developer and transmission owner for all CT – natural gas project MW in PJM interconnection queue: March 31, 2019

			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	1,097.0	190.0	0.0	0.0	466.0	1,753.0
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	122.7	786.0	0.0	0.0	0.0	908.7
		Unrelated	1,033.6	1,116.7	0.0	0.0	75.5	2,225.8
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	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	230.0	404.4	0.0	0.0	173.0	807.4
	BGE	Related	0.0	10.0	0.0	0.0	0.0	10.0
		Unrelated	153.6	13.0	0.0	0.0	0.0	166.6
	ComEd	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,190.0	257.0	48.0	0.0	10.0	1,505.0
	DPL	Related	0.0	351.0	0.0	0.0	0.0	351.0
		Unrelated	0.0	1,226.0	0.0	0.0	0.0	1,226.0
	PECO	Related	0.0	5.0	0.0	0.0	0.0	5.0
		Unrelated	29.0	567.0	0.0	0.0	0.5	596.5
	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
FirstEnergy	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	44.1	0.0	0.0	0.0	44.1
	PENELEC	Related	0.0	5.0	0.0	0.0	0.0	5.0
		Unrelated	481.0	381.9	0.0	19.9	541.9	1,424.7
OVEC	OVEC	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
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	122.7	2,107.0	0.0	0.0	906.1	3,135.8
		Unrelated	4,477.2	6,817.0	253.0	219.9	1,545.8	13,312.9

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 March 31, 2019, by transmission owner and project status. Of the 9,560.7 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. Dominion is the Transmission Owner with the highest percentage of affiliates building wind projects in their own service territory. Of the 8,294.1 MW that entered the queue during the time period of January 1, 1997, through March 31, 2019, 146.0 MW (1.8 percent) have been submitted by Dominion or one of their affiliated companies.

Table 12-38 Relationship between project developer and transmission owner for all wind project MW in PJM interconnection queue: March 31, 2019

			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	5,137.3	2,738.7	150.0	722.0	20,353.2	29,101.2
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	2,700.6	102.5	332.0	76.6	4,936.4	8,148.1
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	2,803.6	7.5	0.0	0.0	3,651.4	6,462.5
	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	8,251.2	2,688.0	974.0	0.0	22,624.8	34,538.0
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	599.8	0.0	0.0	0.0	2,816.8	3,416.6
	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
FirstEnergy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	534.0	1,004.0	260.0	309.4	3,234.1	5,341.5
	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	5,943.2	0.0	0.0	0.0	0.0	5,943.2
	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	995.5	70.0	100.0	5,520.3	6,806.2
OVEC	OVEC	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
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	290.3	226.5	0.0	98.0	3,248.1	3,862.9
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	27,296.3	7,762.7	1,786.0	1,306.0	69,879.0	108,030.0

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 March 31, 2019, by transmission owner and project status. Of the 1,835.2 solar project MW that have achieved in service or under construction status during this time period, 550.5 MW (30.0 percent) have been developed by Transmission Owners building in their own service territory. BGE is the Transmission Owner with the highest percentage of affiliates building solar projects in their own service territory. Of the 58.4 MW that entered the queue during the time period of January 1, 1997, through March 31, 2019, 20.0 MW (34.2 percent) have been submitted by BGE or one of their affiliated companies.

Table 12-39 Relationship between project developer and transmission owner for all solar project MW in PJM interconnection queue: March 31, 2019

			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	11,006.4	0.0	0.0	50.0	6,663.8	17,720.3
AES	DAY	Related	0.0	0.0	0.0	0.0	21.5	21.5
		Unrelated	1,117.0	2.5	0.0	20.0	502.4	1,641.9
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	80.0	0.0	0.0	0.0	0.0	80.0
Dominion	Dominion	Related	420.3	329.4	74.9	0.0	231.9	1,056.5
		Unrelated	14,797.5	349.6	179.9	0.0	10,168.0	25,495.0
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	1,412.0	0.0	0.0	0.0	309.9	1,721.9
Exelon	AECO	Related	0.0	0.0	0.0	0.0	8.3	8.3
		Unrelated	456.4	57.3	0.0	0.0	1,714.0	2,227.7
	BGE	Related	0.0	0.0	0.0	0.0	20.0	20.0
		Unrelated	4.0	1.1	0.0	0.0	33.3	38.4
	ComEd	Related	0.0	9.0	0.0	0.0	0.0	9.0
		Unrelated	2,933.5	0.0	0.0	0.0	1,836.8	4,770.3
	DPL	Related	0.0	7.4	0.0	0.0	0.0	7.4
		Unrelated	1,516.7	117.0	26.0	0.0	1,561.2	3,220.9
	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	120.1	0.0	0.0	0.0	184.5	304.6
FirstEnergy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,575.5	53.0	10.0	266.3	1,586.7	3,491.6
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,319.0	0.0	0.0	0.0	271.1	1,590.1
	JCPL	Related	0.0	0.0	0.0	0.0	12.0	12.0
		Unrelated	133.0	309.6	51.9	8.0	1,385.4	1,888.0
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	621.6	0.0	0.0	58.0	487.0	1,166.6
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	770.9	0.0	0.0	0.0	171.7	942.6
OVEC	OVEC	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
PPL	PPL	Related	19.8	0.0	0.0	0.0	0.0	19.8
		Unrelated	516.4	15.0	0.0	0.0	383.7	915.1
PSEG	PSEG	Related	33.2	111.1	4.0	0.0	36.4	184.7
		Unrelated	73.5	82.4	26.1	6.0	444.7	632.7
Con Ed	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	60.0	0.0	0.0	0.0	0.0	60.0
Total		Related	541.3	471.6	78.9	10.0	386.5	1,488.2
		Unrelated	38,911.6	990.8	293.9	408.3	28,028.6	68,633.2

Regional Transmission Expansion Plan (RTEP)[38]

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.

The RTEP process initially considered only factors such as load growth and the generation interconnection requests in its development of the 15 year plan. Currently, the RTEP process includes a broader range of inputs including 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 six backbone projects under development, the Surry-Skiffes Creek 500kV Line, the Loudoun-Brambleton 500kV Line, the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV, the conversion of the Robinson Park-Sorenson lines to double circuit 345kV and the Meadow Lake-Reynolds 345kV Line rebuild.[39]

Market Efficiency Process

PJM's Regional Transmission Expansion Plan (RTEP) process includes a market efficiency analysis. The stated 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.[40] 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.[41]

PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. That analysis evaluated the historical sources of congestion on 25

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

39 See PJM, "*2018 RTEP Process Scope and Input Assumptions White Paper*," at 25. <https://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en>.

40 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>.

41 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>.

flowgates.[42] The proposal window was open from August 12, 2013, through September 26, 2013. PJM received 38 proposals from six entities. One project was approved by the PJM Board.

The first market efficiency cycle conducted under Order 1000 was performed during the 2014/2015 RTEP long term window. That analysis evaluated the historical sources of congestion on 77 flowgates, 57 of which could be addressed by market efficiency projects. 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, with the remaining submissions addressing reliability issues identified by PJM. A total of 14 projects were approved by the PJM Board for this window, 13 of which were market efficiency projects and one of which was for reliability.

The second market efficiency cycle was performed during the 2016/2017 RTEP long term window. That analysis evaluated the historical sources of congestion on a total of four flowgates, all four of which could be addressed by market efficiency projects. The proposal window was open from November 1, 2016, through February 28, 2017. PJM received 96 proposals, all 96 of which addressed market efficiency issues. A total of four projects were approved by the PJM Board for this window, all 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 was open between November 1, 2018 and February 28, 2019. PJM received 22 proposals for one identified source of congestion.

In 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.[43] [44] [45] [46] 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.[47]

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 net present value of calculated energy market benefits and calculated reliability pricing model (RPM) benefits for a 15 year period, starting with the projected in service date of the project. Benefits are reductions in estimated load charges and production costs in the energy market and reductions in estimated load capacity payments and in system capacity costs in the capacity market. 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 uses an energy market simulation tool that produces an hourly least-cost, security constrained market solution,

42 Historical congestion drivers are identified using the historical congestion tables presented in the *State of the Market Report for PJM*, Section 11: Congestion and Marginal Losses, historical analysis of real time constraints, the NERC Book of Flowgates and PROMOD simulations.

43 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>.

44 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>.

45 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>.

46 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>.

47 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>.

including 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. Energy Production Costs are the sum of generation payments in the energy market simulation in each modeled year. The change in the Energy Production costs in each modeled year is 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 estimated value of any Auction Revenue Rights (ARR) that sink in that zone. Estimated ARR credits are calculated for each simulated year using the most recent planning year's actual ARR MW combined with FTR prices assumed to be equal to the market simulation's CLMP differences between ARR source and sink points. The value of the ARR rights with and without the RTEP project is evaluated based on changes in modeled 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.

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.

The definition of the benefit in the RPM benefit analysis depends on whether the project is regional or subregional. For a regional project, the RPM 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 current rules governing benefit/cost analysis of competing transmission projects do not correctly measure the relative costs and benefits of transmission projects. The current rules explicitly ignore the increased congestion costs that an RTEP project may create in a subset of zones when calculating the energy market benefits. The current rules do not account for the risk associated with the fact that the project costs are nonbinding estimates. All costs should be included in all zones and LDAs.

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).[48]

The allocation of costs to each RTO for TMEPs will be in proportion to the benefits received.[49]

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.[50] [51]

48 See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000 (December 30, 2016).
49 See *PJM Interconnection, L.L.C*, Docket No. ER17-729-000 (December 30, 2016).
50 See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000, ER17-721-000 and ER17-729-000 (Not Consolidated) (November 2, 2017).
51 161 FERC ¶ 61,005.

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, 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.[52]

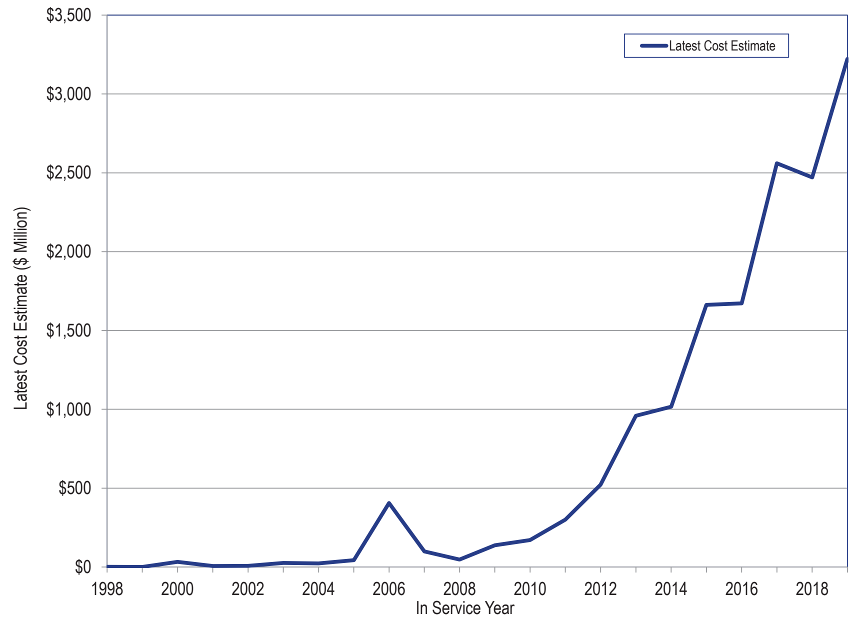
The 2018 TMEP analysis included the investigation of congestion on 61 market to market flowgates. The study resulted in the evaluation of 19 potential upgrades, resulting in the recommendation of two TMEP projects. The two projects address $25 million in historical congestion, with a TMEP benefit of $31.9 million. The projects have a total cost of $4.5 million, with a 7.1 average benefit/cost ratio. PJM and MISO presented the two recommended projects to their boards in December, 2018, and both boards approved the projects.[53]

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."[54] Supplemental projects are selected solely by the Transmission Owner and no PJM approval is needed. Supplemental projects are currently exempt from the Order No. 1000 competitive process. Transmission owners have a clear incentive to increase investments in rate base given that transmission owners are paid for these projects on a cost of service basis.

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.

Figure 12-3 Latest cost estimate of supplemental projects by expected in service year: 1998 through 2019



52 See PJM. "*MISO PJM IPSAC*," (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.
53 See PJM. "*MISO PJM IPSAC*," (January 18, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20190118/20190118-ipsac-presentation.ashx>.
54 See PJM. "*Transmission Construction Status*" (January 23, 2018) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

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 615.0 percent, from 20 for years 1998 through 2007 (pre Order 890) to 143 for years 2008 through 2019 (post Order 890).

Table 12-40 Number of supplemental projects by expected in service year and zone: 1998 through 2040

Year	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
1998	0	0	0	0	0	0	0	0	0	0	3	0	0	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	0	0	2
2000	0	0	0	0	0	0	0	0	0	0	11	0	0	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	0	0	14
2002	0	0	0	0	0	0	0	0	0	0	10	0	0	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	0	2	0	0	0	0	15
2004	5	0	10	0	0	9	0	0	0	0	12	0	2	0	0	0	0	0	0	2	0	40
2005	4	2	8	0	0	4	0	0	0	1	14	0	1	0	0	1	2	0	0	2	0	39
2006	4	2	5	0	0	6	0	0	0	0	9	0	1	0	0	0	1	0	2	1	0	31
2007	1	1	5	0	4	5	0	0	4	0	6	0	0	0	0	0	2	0	1	6	0	35
2008	3	0	15	0	1	6	0	0	1	7	3	0	0	1	0	0	0	0	3	1	0	41
2009	3	1	6	0	1	8	0	0	3	3	5	0	0	0	0	5	1	0	0	2	0	38
2010	0	6	7	0	3	4	0	0	6	3	0	0	1	2	0	2	0	0	2	5	0	41
2011	0	8	8	0	0	2	0	0	5	2	0	0	1	0	0	4	0	0	3	4	0	37
2012	0	5	6	4	1	2	0	7	3	16	1	0	2	0	0	1	0	0	4	11	0	63
2013	5	21	4	5	0	11	0	6	5	13	1	0	1	1	0	1	0	1	13	19	0	107
2014	2	31	2	8	2	14	0	5	6	18	3	2	2	0	0	1	2	0	9	16	0	123
2015	4	15	2	9	1	37	0	8	4	17	5	4	2	0	0	1	0	4	7	24	0	144
2016	5	13	4	17	0	26	0	6	2	13	4	2	0	1	0	3	2	3	11	30	0	142
2017	8	103	3	26	1	23	0	3	8	34	11	5	0	3	0	0	3	1	21	43	0	296
2018	10	155	4	13	1	21	0	15	4	28	7	4	0	0	0	2	0	1	18	30	0	313
2019	5	193	2	29	6	16	2	22	3	13	7	5	0	1	0	1	17	1	21	25	0	369
2020	7	100	0	15	2	3	0	5	1	10	4	4	0	5	0	0	4	0	23	22	0	205
2021	3	65	0	8	0	1	2	0	1	10	3	3	1	2	0	0	0	0	24	26	1	150
2022	5	6	0	0	2	0	3	2	0	0	4	0	0	0	0	0	0	2	20	16	0	60
2023	5	3	0	0	0	1	5	0	2	1	2	0	1	3	0	0	1	0	12	7	0	43
2024	3	0	1	0	7	0	0	0	0	0	0	0	1	0	0	0	0	0	13	0	0	25
2025	3	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	6	0	0	10
2026	0	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	13	0	0	17
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	3
2028	0	0	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	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	0	0	4
2031	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	0	0	4
Total	88	730	92	134	37	199	12	79	58	189	151	29	16	19	0	22	37	13	237	292	1	2,435

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 1,649.6 percent, from $64.5 million for years 1998 through 2007 (pre Order 890) to $1,228.5 million for years 2008 through 2019 (post Order 890).

Table 12-41 Latest cost estimate by expected in service year and zone ($ millions): 1998 through 2040

Year	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	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	$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	$0.00	$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	$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	$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	$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	$0.00	$9.60	$0.00	$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	$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	$0.00	$0.50	$0.00	$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	$0.00	$1.50	$0.00	$4.63	$18.80	$0.00	$406.15
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	$0.00	$0.34	$2.25	$0.00	$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	$0.00	$1.60	$0.00	$0.00	$47.33
2009	$0.77	$0.90	$12.22	$0.00	$5.00	$21.11	$0.00	$0.00	$19.60	$2.12	$7.36	$0.00	$0.00	$0.00	$0.00	$48.10	$2.73	$0.00	$0.00	$17.60	$0.00	$137.51
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	$0.00	$31.80	$0.00	$0.00	$1.08	$17.72	$0.00	$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	$0.00	$113.30	$0.00	$0.00	$0.78	$34.60	$0.00	$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	$0.00	$12.60	$0.00	$0.00	$8.91	$223.01	$0.00	$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	$0.00	$22.50	$0.00	$2.40	$75.84	$503.72	$0.00	$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	$0.00	$13.30	$1.30	$0.00	$33.47	$309.70	$0.00	$1,016.92
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	$0.00	$33.80	$0.00	$42.50	$50.17	$743.91	$0.00	$1,662.36
2016	$73.54	$79.98	$18.40	$182.70	$0.00	$308.15	$0.00	$15.13	$26.95	$40.68	$26.60	$0.25	$0.00	$2.37	$0.00	$86.40	$0.40	$7.80	$58.76	$744.18	$0.00	$1,672.29
2017	$66.28	$642.74	$8.60	$142.05	$0.09	$145.97	$0.00	$65.01	$3.62	$105.86	$92.29	$2.21	$0.00	$14.70	$0.00	$0.00	$8.30	$12.00	$261.74	$988.92	$0.00	$2,560.38
2018	$71.73	$768.52	$14.80	$64.52	$4.08	$92.94	$0.00	$75.29	$4.98	$182.05	$75.44	$10.87	$0.00	$0.00	$0.00	$47.60	$0.00	$156.00	$185.30	$716.93	$0.00	$2,471.05
2019	$57.10	$1,359.37	$0.93	$195.54	$71.01	$130.29	$7.81	$127.73	$14.90	$32.80	$37.00	$21.54	$0.00	$2.40	$0.00	$2.00	$92.20	$70.00	$295.94	$703.56	$0.00	$3,222.12
2020	$82.92	$986.66	$0.00	$127.30	$62.50	$61.00	$0.00	$45.30	$16.80	$27.23	$32.92	$22.55	$0.00	$36.60	$0.00	$0.00	$76.70	$0.00	$378.00	$1,977.08	$0.00	$3,933.56
2021	$24.26	$1,004.31	$0.00	$194.10	$0.00	$1.00	$14.00	$0.00	$20.00	$75.40	$34.01	$16.36	$16.00	$40.10	$0.00	$0.00	$0.00	$0.00	$314.50	$935.15	$17.00	$2,706.19
2022	$91.80	$50.20	$0.00	$0.00	$263.00	$0.00	$10.25	$21.42	$0.00	$0.00	$35.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$527.00	$422.70	$970.00	$0.00	$2,391.37
2023	$46.84	$52.60	$0.00	$0.00	$0.00	$1.00	$32.85	$0.00	$40.00	$32.00	$29.72	$0.00	$8.50	$16.30	$0.00	$0.00	$200.00	$0.00	$148.90	$177.00	$0.00	$785.71
2024	$0.00	$0.00	$3.60	$0.00	$223.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22.00	$0.00	$0.00	$0.00	$0.00	$0.00	$281.53	$0.00	$0.00	$530.13
2025	$82.99	$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	$0.00	$143.00	$0.00	$0.00	$233.49
2026	$0.00	$0.00	$0.00	$0.00	$45.00	$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	$312.24	$0.00	$0.00	$357.24
2027	$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	$54.30	$0.00	$0.00	$54.30
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	$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	$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	$0.00	$62.00	$0.00	$0.00	$62.00
2031	$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	$0.00	$0.00
2032	$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	$0.00	$0.00
2033	$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	$0.00	$0.00
2034	$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	$0.00	$0.00
2035	$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	$0.00	$0.00
2036	$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	$0.00	$0.00
2037	$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	$0.00	$0.00
2038	$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	$0.00	$0.00
2039	$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	$0.00	$0.00
2040	$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	$8.33	$0.00	$0.00	$8.33
Total	$636.01	$6,149.05	$138.89	$1,020.84	$763.54	$1,336.64	$64.91	$402.42	$349.78	$1,005.73	$491.16	$75.72	$66.25	$121.15	$0.00	$411.90	$392.73	$817.70	$3,104.05	$9,084.13	$17.00	$26,449.59

The role of supplemental projects in the market efficiency process needs to be modified. It is not clear how a supplemental project can be a market efficiency project that has been identified as a PJM issue based on a cost/benefit analysis and why such a project should not be subject to competition. The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated.

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.[55] End of life transmission projects fall under the Transmission Owner Form 715 Planning Criteria, and are currently exempt from the competitive planning process.[56] 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.

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.[57]
- **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.[58]
- **FERC 715 (Transmission Owner (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.[59]
- **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.[60]

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 recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. The proposed comparative framework, along with the advice and recommendation of the MMU, will be presented to the PJM Planning Committee for review and comment prior to an MRC vote. The comparative framework will be presented at the December 2019 meeting of the MRC.

55 The useful life of a transmission investment typically exceeds its depreciable life.
56 See PJM Operating Agreement Schedule 6 § 1.5.8(o).
57 See PJM Operating Agreement Schedule 6 § 1.5.8(m).
58 See PJM Operating Agreement Schedule 6 § 1.5.8(n).
59 See PJM Operating Agreement Schedule 6 § 1.5.8(o).
60 See PJM Operating Agreement Schedule 6 § 1.5.8(p).

Board Authorized Transmission Upgrades

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, are periodically presented to the PJM Board of Managers for authorization.[61]

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.

On February 12, 2019, the PJM Board of Managers authorized an additional $272.0 million in transmission upgrades and additions. As of March 31, 2019, the PJM Board has approved $38.5 billion in system enhancements since 1999.

Qualifying Transmission Upgrades (QTU)

A Qualifying Transmission Upgrade (QTU) is: "a proposed enhancement or addition to the transmission system that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade."[62] If a QTU that was cleared in a BRA is not completed by the start of the Delivery Year, the submitting party is required to provide replacement capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of December 31, 2018, no QTUs have cleared a BRA.

QTU projects are submitted and tracked through the PJM queue.[63] A total of 51 QTU projects have entered the queue since 2007. Of the 51 submitted QTU projects, 37 projects (72.5 percent) have been withdrawn, five (10.0 percent) are in service and nine (17.5 percent) are currently in active development.

Cost Allocation

In response to complaints against PJM RTEP Baseline Upgrade Filings in 2014 that included cost allocations for $1.5 billion in baseline transmission enhancements and expansions, on November 24, 2015, FERC issued an order directing investigation of "whether there is a definable category of reliability projects within PJM for which the solution-based DFAX cost allocation method may not be just and reasonable, such as projects addressing reliability violations that are not related to flow on the planned transmission facility, and whether an alternative just and reasonable *ex ante* cost allocation method could be established for any such category of projects."[64] FERC convened a technical conference on January 12, 2016, to address the complaints in multiple proceedings and to address these two core issues.[65]

The issues identified in the complaints and at the technical conference include: whether the solutions based allocation method is appropriate for upgrades not related to transmission overload issues; whether the solutions based allocation method correctly identifies all the beneficiaries of the upgrades; whether it is reasonable to allocate a level of costs to a merchant transmission project that could force bankruptcy; and whether the significant shifts in allocation that result from use of the 0.01 distribution factor cutoff are appropriate.

It is clear that the allocation issues are difficult. Nonetheless, the allocation methods affect the efficiency of the markets and the incentives for merchant transmission owners to compete to build new transmission. The use of the arbitrary 0.01 distribution factor cutoff can result in large and inappropriate

61 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.
62 See OATT § 1 (Qualifying Transmission Upgrade).
63 See PJM "New Services Queue," at <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.
64 153 FERC ¶ 61,245 at P 35 (Nov. 24, 2015) (Docket Nos. ER15-2562 and ER15-2563.).
65 See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).

shifts in cost allocation. If the intent of the use of the 0.01 cutoff is to help eliminate small, arbitrary cost allocations to geographically distant areas, this could be achieved by adding a threshold for a minimum usage impact on the line. The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum impact on the load on the line based on a complete analysis of the intent of the allocation and the impacts of the allocation.

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.[66] When a reportable transmission facility needs to be taken out of service, the transmission owner is required to submit an outage request as early as possible.[67] The specific timeline is shown in Table 12-43.[68]

Transmission outages have significant impacts on PJM markets, including impacts on FTR auctions, on congestion, and on expected market outcomes in the day-ahead and real-time markets. The efficient functioning of the markets depends on clear, enforceable rules governing transmission outages.

The outage data for the FTR market are for outages scheduled to occur in the 2017/2018 planning period and the first ten months of the 2018/2019 planning period, regardless of when they were initially submitted.[69] The outage data for the day-ahead market are for outages scheduled to occur from January 2015 through March 2019.

Transmission outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days; greater than five calendar days; less than or equal to five calendar days.[70] Table 12-42 shows that 75.8 percent of requested outages were planned for less than or equal to five days and 8.8 percent of requested outages were planned for greater than 30 days in the first ten months of 2018/2019 planning period. Table 12-42 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.

Table 12-42 Transmission facility outage request summary by planned duration: June 2017 through March 2019

	2017/2018		2018/2019	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	16,205	75.9%	13,364	75.8%
>5 & <=30	3,489	16.3%	2,731	15.5%
>30	1,654	7.7%	1,546	8.8%
Total	21,348	100.0%	17,641	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.[71]

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 PJM can accurately model market conditions.[72]

66 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 3: Transmission Operations, Rev. 54 (Dec. 10, 2018).

67 See PJM, "Manual 3: Transmission Operations," Rev. 54 (Dec. 10, 2018).

68 See PJM, "Manual 3: Transmission Operations," Rev. 54 (Dec. 10, 2018).

69 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.

70 *Id.* at 70.

71 See PJM. "Manual 3: Transmission Operations," Rev. 54 (Dec. 10, 2018).

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

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 first ten months of 2018/2019 planning period, 49.4 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: June 2017 through March 2019

	2017/2018				2018/2019			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	8,418	7,787	16,205	48.1%	6,996	6,368	13,364	47.7%
>5 & <=30	1,712	1,777	3,489	50.9%	1,308	1,423	2,731	52.1%
>30	609	1,045	1,654	63.2%	622	924	1,546	59.8%
Total	10,739	10,609	21,348	49.7%	8,926	8,715	17,641	49.4%

Once received, PJM processes outage requests in priority order: emergency transmission outage request; transmission outage request submitted on time; and transmission outage request submitted late. Transmission outage requests that are submitted late may be approved if the outage does not affect the reliability of PJM or cause congestion in the system.[73]

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.[74] Table 12-45 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the first ten months of 2018/2019 planning period, 13.8 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: June 2017 through March 2019

	2017/2018				2018/2019			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	2,051	14,154	16,205	12.7%	1,744	11,620	13,364	13.0%
>5 & <=30	399	3,090	3,489	11.4%	427	2,304	2,731	15.6%
>30	249	1,405	1,654	15.1%	262	1,284	1,546	16.9%
Total	2,699	18,649	21,348	12.6%	2,433	15,208	17,641	13.8%

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."[75]

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.

73 See PJM, "Manual 3: Transmission Operations," Rev. 54 (Dec. 10, 2018). The following language was removed from Manual 3 Rev. 50: PJM retains the right to deny all jobs submitted after 8 a.m. three days prior to the requested start date unless the request is an emergency job or an exception request (i.e. a generator tripped and the Transmission Owner is taking advantage of a situation that was not available before the unit trip).

74 PJM. "Manual 3: Transmission Operations," Rev. 54 (Dec. 10, 2018).

75 PJM added this definition to Manual 38 in February 2017. PJM. "Manual 38: Operations Planning," Rev. 11 (Feb. 1, 2018).

Table 12-46 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the first ten months of the 2018/2019 planning period, 7.5 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 4.9 percent (65 out of 1,331) were denied by PJM in the first ten months of 2018/2019 planning period and 23.2 percent (309 out of 1,331) 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: June 2017 through March 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	15,111	16,205	6.8%	950	12,414	13,364	7.1%
>5 & <=30	357	3,132	3,489	10.2%	240	2,491	2,731	8.8%
>30	151	1,503	1,654	9.1%	141	1,405	1,546	9.1%
Total	1,602	19,746	21,348	7.5%	1,331	16,310	17,641	7.5%

Table 12-47 shows the outage requests summary by received status, congestion status and emergency status. In the first ten months of 2018/2019 planning period, 35.7 percent of requests were submitted late and were nonemergency while 1.2 percent of requests (216 out of 17,641) were late, nonemergency, and expected to cause congestion. In the 2017/2018 planning period, 37.2 percent of request were submitted late and were nonemergency while 1.4 percent of requests (297 out of 21,348) were late, nonemergency, and expected to cause congestion.

Table 12-47 Transmission facility outage request summary by received status, emergency and congestion: June 2017 through March 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	2,593	2,678	12.5%	62	2,356	2,418	13.7%
	Non Emergency	297	7,634	7,931	37.2%	216	6,081	6,297	35.7%
On Time	Emergency	3	18	21	0.1%	2	13	15	0.1%
	Non Emergency	1,217	9,501	10,718	50.2%	1,051	7,860	8,911	50.5%
Total		1,602	19,746	21,348	100.0%	1,331	16,310	17,641	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.[76] 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 (65 out of 1,331) were denied by PJM in the first ten months of 2018/2019 planning period, 63.6 percent were complete and 23.2 percent (309 out of 1,331) 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

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

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: June 2017 through March 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%	7	55	0	0	62	88.7%
	Non Emergency	47	220	9	18	297	74.1%	44	140	14	18	216	64.8%
On Time	Emergency	2	1	0	0	3	33.3%	0	2	0	0	2	100.0%
	Non Emergency	254	840	76	40	1,217	69.0%	258	649	93	47	1,051	61.8%
Total		314	1,135	85	58	1,602	70.8%	309	846	107	65	1,331	63.6%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[77] 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, 297 nonemergency outage requests were submitted late and expected to cause congestion. The expected impact on congestion is the basis for PJM's treatment of late outage requests. But there is no rule or clear definition of this congestion analysis in the PJM Manuals. The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review.

Rescheduling Transmission Facility Outage Requests

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 2017/2018 planning period and the first ten months of 2018/2019 planning period 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 first ten months of 2018/2019 planning period, 32.7 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 12.3 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2017/2018 planning period, 32.7 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 12.6 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

77 PJM Operating Agreement Schedule 1 § 1.9.2.

Table 12-49 Rescheduled and cancelled transmission outage request summary: June 2017 through March 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	16,205	3,656	22.6%	2,385	14.7%	13,364	3,189	23.9%	1,946	14.6%
>5 & <=30	3,489	2,171	62.2%	236	6.8%	2,731	1,657	60.7%	180	6.6%
>30	1,654	1,150	69.5%	66	4.0%	1,546	920	59.5%	50	3.2%
Total	21,348	6,977	32.7%	2,687	12.6%	17,641	5,766	32.7%	2,176	12.3%

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.[78] 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.[79] 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 rescheduling rule allows TOs to avoid the timing requirements associated with outages exceeding five days.

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

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-43) 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.

More than one outage request can be submitted for the same transmission equipment. In order to accurately present the results, Table 12-50 shows equipment outages by the equipment instead of by outage request.

Table 12-50 shows that there were 11,046 transmission equipment planned outages in the first ten months of 2018/2019 planning period, of which 1,509 were longer than 30 days, and of which 171 or 1.5 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

Table 12-50 Transmission outage summary: June 2017 through March 2019

		2017/2018		2018/2019	
Planned Duration (Days)	Divided into Shorter Periods	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
> 30	No	1,442	11.3%	1,338	12.1%
	Yes	244	1.9%	171	1.5%
<= 30		11,032	86.7%	9,537	86.3%
Total		12,718	100.0%	11,046	100.0%

78 PJM, "Manual 3: Transmission Operations," Rev. 54 (Dec. 10, 2018).
79 *Id.*

Table 12-51 shows the details of long duration (> 30 days) outages when combining the duration of the outage requests for the same equipment. The actual duration of scheduled outages would be longer than 30 days if the duration of the outage requests were appropriately combined for the same equipment. An effective duration was calculated for each piece of equipment by subtracting the start date of the earliest outage request from the end date of the latest outage request of the equipment. In the first ten months of 2018/2019 planning period, there were 169 outages with a combined duration longer than 31 days.

Table 12-51 Equipment outages: June 2017 through March 2019

	2017/2018		2018/2019	
Effective Duration of Outage	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
<=31	6	2.5%	2	1.2%
>31 & <=62	25	10.2%	27	15.8%
>62 & <=93	18	7.4%	16	9.4%
>93	195	79.9%	126	73.7%
Total	244	100.0%	171	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 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.[80]

In the first ten months of 2018/2019 planning period, 224 outage requests were included in the annual FTR market outage list and 17,417 outage requests were not included.[81] In the 2017/2018 planning period, 225 outage requests were included in the annual FTR market outage list and 21,123 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 8.0 percent of the outage requests modeled in the Annual FTR Market for the first ten months of 2018/2019 planning period had a planned duration of less than two weeks and that 16.5 percent of the outage requests (37 out of 224) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 4.0 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 16.9 percent of the outage requests (38 out of 225) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

80 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).
81 PJM's treatment of transmission outages in the FTR models is discussed in: *See* the *2018 State of the Market Report for PJM*, Section 13: FTRs and ARRs: Supply and Demand.

Table 12-52 Annual FTR market modeled transmission facility outage requests by received status: June 2017 through March 2019

	2017/2018				2018/2019			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	6	3	9	4.0%	16	2	18	8.0%
>=2 weeks & <2 months	65	12	77	34.2%	58	8	66	29.5%
>=2 months	116	23	139	61.8%	113	27	140	62.5%
Total	187	38	225	100.0%	187	37	224	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 first ten months of 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: June 2017 through March 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	6	6	100.0%	0	16	16	100.0%
	>=2 weeks & <2 months	0	65	65	100.0%	0	58	58	100.0%
	>=2 months	0	116	116	100.0%	0	113	113	100.0%
	Total	0	187	187	100.0%	0	187	187	100.0%
Late	<2 weeks	0	3	3	100.0%	0	2	2	100.0%
	>=2 weeks & <2 months	0	12	12	100.0%	0	8	8	100.0%
	>=2 months	0	23	23	100.0%	3	24	27	88.9%
	Total	0	38	38	100.0%	3	34	37	91.9%

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, none of all the annual FTR market modeled outages expected to occur in the first ten months of 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, 10.5 percent (4 out of 38) were expected to cause congestion.

Table 12-54 Annual FTR market modeled transmission facility outage requests by congestion and received status: June 2017 through March 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	3	6	50.0%	8	8	16	50.0%
	>=2 weeks & <2 months	18	47	65	27.7%	17	41	58	29.3%
	>=2 months	37	79	116	31.9%	30	83	113	26.5%
	Total	58	129	187	31.0%	55	132	187	29.4%
Late	<2 weeks	0	3	3	0.0%	0	2	2	0.0%
	>=2 weeks & <2 months	1	11	12	8.3%	0	8	8	0.0%
	>=2 months	3	20	23	13.0%	0	27	27	0.0%
	Total	4	34	38	10.5%	0	37	37	0.0%

Table 12-55 shows that 22.7 percent of outage requests modeled in the annual FTR market for the first ten months of 2018/2019 planning period and with a duration of two weeks or longer but shorter than two months were cancelled after the FTR auction was open, compared to 32.5 percent for the 2017/2018 planning period. Table 12-55 also shows that 21.4 percent of outages requests modeled in the Annual FTR Market for the first ten months of 2018/2019 planning period and with a duration of two months or longer were cancelled, compared to 12.9 percent for the 2017/2018 planning period.

Table 12-55 Annual FTR market modeled transmission facility outage requests by processed status: June 2017 through March 2019

		2017/2018		2018/2019	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	0	0.0%	2	11.1%
	Denied	0	0.0%	0	0.0%
	Approved	0	0.0%	0	0.0%
	Cancelled	3	33.3%	3	16.7%
	Revised	0	0.0%	0	0.0%
	Active	0	0.0%	0	0.0%
	Completed	6	66.7%	13	72.2%
	Total	9	100.0%	18	100.0%
>=2 weeks & <2 months	In Progress	7	9.1%	11	16.7%
	Denied	1	1.3%	0	0.0%
	Approved	0	0.0%	0	0.0%
	Cancelled	25	32.5%	15	22.7%
	Revised	0	0.0%	0	0.0%
	Active	0	0.0%	1	1.5%
	Completed	44	57.1%	39	59.1%
	Total	77	100.0%	66	100.0%
>=2 months	In Progress	26	18.7%	21	15.0%
	Denied	0	0.0%	2	1.4%
	Approved	2	1.4%	1	0.7%
	Cancelled	18	12.9%	30	21.4%
	Revised	0	0.0%	1	0.7%
	Active	2	1.4%	26	18.6%
	Completed	91	65.5%	59	42.1%
	Total	139	100.0%	140	100.0%

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the first ten months of 2018/2019 planning period, 224 outage requests were modeled and 17,417 outage requests were not modeled in the Annual FTR Market. In the 2017/2018 planning period, 225 outage requests were modeled and 21,123 outage requests were not modeled in the Annual FTR Market.

Table 12-56 shows that 10.5 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 first ten months of 2018/2019 planning period compared to 21.2 percent in the 2017/2018 planning period.

Table 12-56 Transmission facility outage requests not modeled in Annual FTR Auction: June 2017 through March 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	1,351	8,019	85.6%	282	8,546	96.8%	1,600	6,076	79.2%	259	6,968	96.4%
>=2 weeks & <2 months	581	412	41.5%	139	1,020	88.0%	603	231	27.7%	161	758	82.5%
>=2 months	149	40	21.2%	215	369	63.2%	205	24	10.5%	220	312	58.6%
Total	2,081	8,471	80.3%	636	9,935	94.0%	2,408	6,331	72.4%	640	8,038	92.6%

Table 12-57 shows that 59.9 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 first ten months of 2018/2019 planning period. It also shows that 85.1 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: June 2017 through March 2019

	2017/2018			2018/2019		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	7,111	8,546	83.2%	5,749	6,968	82.5%
>=2 weeks & <2 months	897	1,020	87.9%	640	758	84.4%
>=2 months	314	369	85.1%	187	312	59.9%
Total	8,322	9,935	83.8%	6,576	8,038	81.8%

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 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 less than or equal to five days. PJM exercises 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.[82] 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 12-61 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

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

Table 12-58 shows that on average, 28.1 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 first ten months of 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: June 2017 through March 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%	536	191	727	26.3%
Nov	453	177	630	28.1%	391	129	520	24.8%
Dec	330	142	472	30.1%	363	129	492	26.2%
Jan	194	78	272	28.7%	199	90	289	31.1%
Feb	214	125	339	36.9%	213	109	322	33.9%
Mar	391	168	559	30.1%	389	146	535	27.3%
Apr	444	204	648	31.5%				
May	396	203	599	33.9%				
Avg	311	137	448	30.6%	304	119	422	28.1%

Table 12-59 shows that on average, 19.8 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the first ten months of 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: June 2017 through March 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	66	7	19	140	0	196	299	727	19.3%
	Nov	39	2	8	119	1	166	185	520	22.9%
	Dec	42	5	5	112	0	96	232	492	22.8%
	Jan	35	3	11	43	1	100	96	289	14.9%
	Feb	36	1	2	67	1	112	103	322	20.8%
	Mar	48	5	14	103	0	155	210	535	19.3%
Average		40	5	10	86	1	117	164	422	19.8%

Table 12-60 shows that on average, 10.9 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 first ten months of 2018/2019 planning period, compared to 10.6 percent in the 2017/2018 planning period. On average, 69.5 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 first ten months of 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: June 2017 through March 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%	757	120	13.7%	389	830	68.1%
Jul	294	48	14.0%	245	608	71.3%	393	64	14.0%	271	643	70.4%
Aug	341	28	7.6%	211	651	75.5%	483	68	12.3%	259	715	73.4%
Sep	859	84	8.9%	256	599	70.1%	819	145	15.0%	283	712	71.6%
Oct	986	89	8.3%	346	867	71.5%	1,233	115	8.5%	329	945	74.2%
Nov	815	83	9.2%	364	792	68.5%	875	71	7.5%	406	860	67.9%
Dec	610	68	10.0%	324	693	68.1%	666	41	5.8%	322	671	67.6%
Jan	565	74	11.6%	286	746	72.3%	556	73	11.6%	370	725	66.2%
Feb	591	51	7.9%	340	700	67.3%	646	96	12.9%	334	734	68.7%
Mar	1,068	219	17.0%	340	802	70.2%	1,118	86	7.1%	382	770	66.8%
Apr	1,203	119	9.0%	446	852	65.6%						
May	1,203	149	11.0%	463	1,084	70.1%						
Avg	765	92	10.6%	328	770	70.3%	755	88	10.9%	335	761	69.5%

Table 12-61 shows that on average, 68.8 percent of late outage requests which were not modeled in the Monthly Balance of Planning Period FTR Auction, submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates, were approved and complete in the first ten months of 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: June 2017 through March 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%	449	643	69.8%
Aug	473	651	72.7%	506	715	70.8%
Sep	406	599	67.8%	480	712	67.4%
Oct	595	867	68.6%	614	945	65.0%
Nov	490	792	61.9%	570	860	66.3%
Dec	508	693	73.3%	468	671	69.7%
Jan	493	746	66.1%	471	725	65.0%
Feb	457	700	65.3%	470	734	64.0%
Mar	569	802	70.9%	568	770	73.8%
Apr	560	852	65.7%			
May	731	1,084	67.4%			
Avg	526	770	68.3%	523	761	68.8%

Transmission Facility Outage Analysis in the Day-Ahead Energy Market

Transmission facility outages also affect the energy market. Just as with the FTR Market, it is critical that outages that affect the operating day are known prior to the submission of offers in the Day-Ahead Energy Market so that market participants can understand market conditions and 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.[83]

There are three relevant time periods for the analysis of the impact of transmission outages on the energy market: 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 available to market participants. The day-ahead market model uses outages included in the day-ahead market save cases as an input. The 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 negative impact on markets. For example, if the list of outages before the day-ahead market was closed was different from the list of outages that included in the day-ahead market save cases, the day-ahead market participant would have inconsistent outage information as what day-ahead market model used.

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 requests 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.

83 PJM, "Manual 3: Transmission Operations," Rev. 54 (Dec. 10, 2018).

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

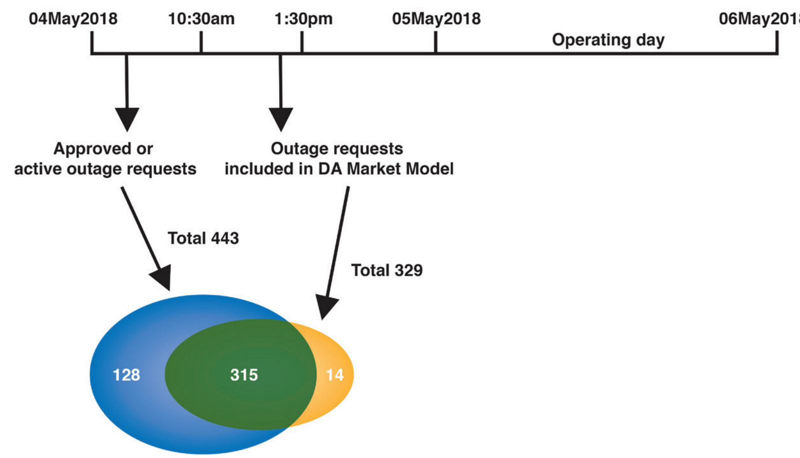


Figure 12-5 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.

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 12-5 Approved or active outage requests: January 2015 through March 2019

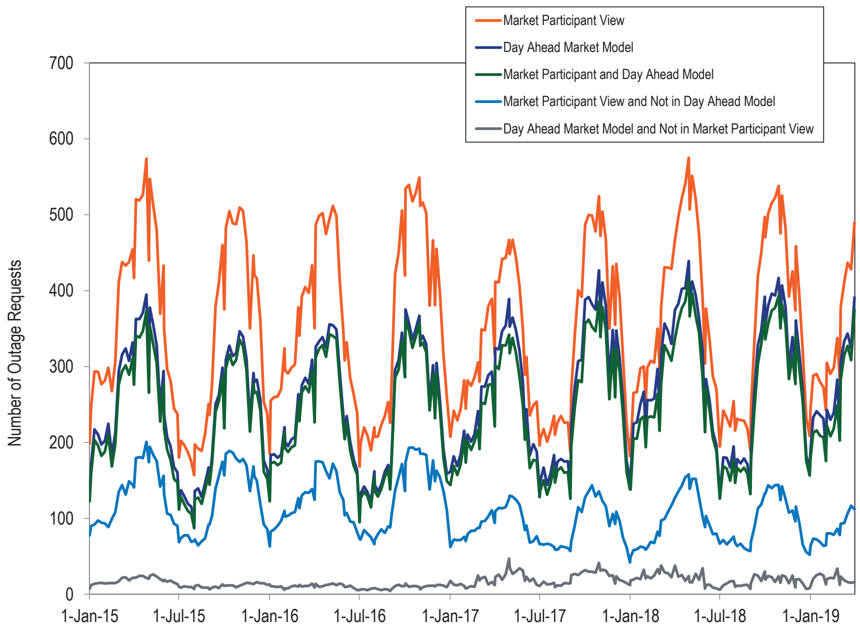


Figure 12-6 Day-ahead market model outages: January 2015 through March 2019

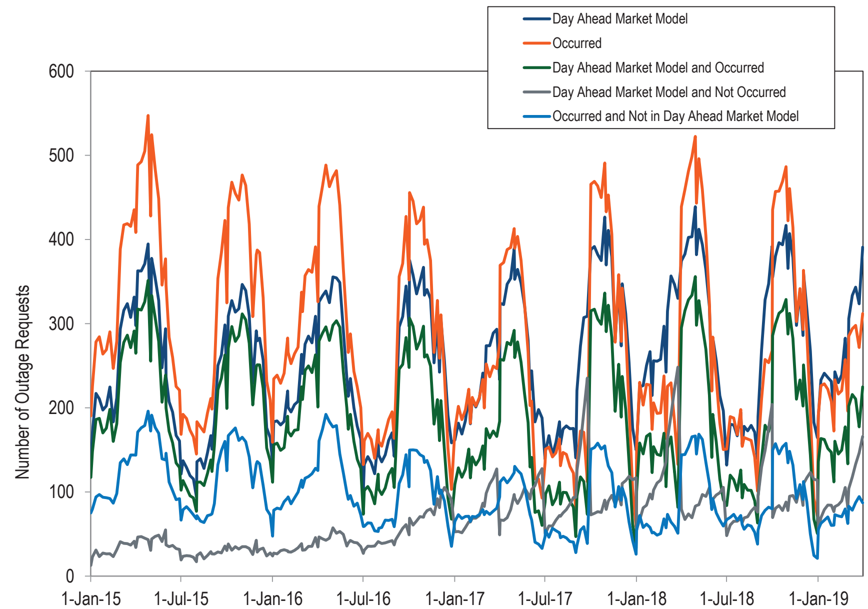


Figure 12-7 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

Figure 12-7 Approved or active outage requests: January 2015 through March 2019

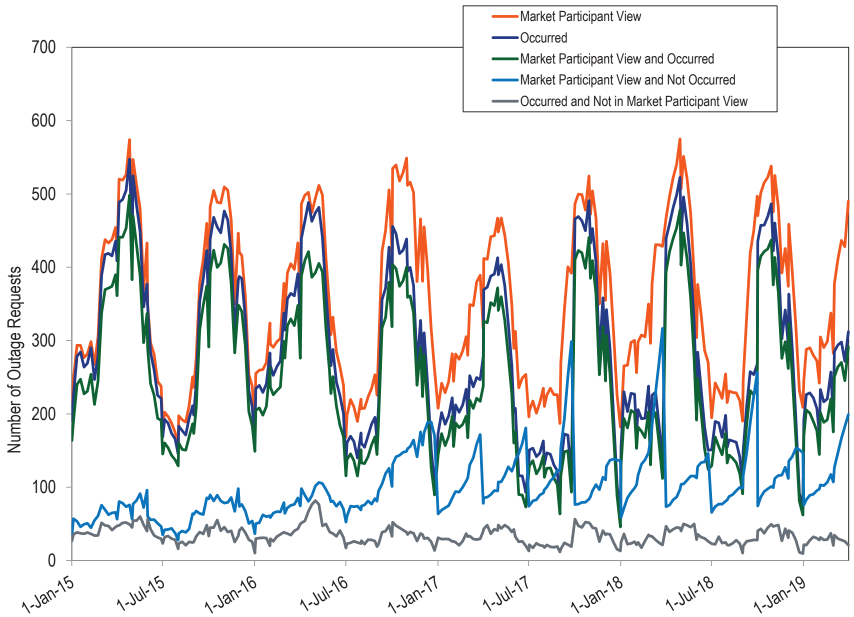


Figure 12-5, Figure 12-6, and Figure 12-7 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or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