# Generation and Transmission Planning[1]

## Overview

### Generation Interconnection Planning

#### Existing Generation Mix

- As of December 31, 2019, PJM had a total installed capacity of 197,574.5 MW, of which 52,667.6 MW (26.7 percent) are coal fired steam units, 49,641.6 MW (25.1 percent) are combined cycle units and 33,452.6 MW (16.9 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 197,574.5 MW of PJM total installed capacity, 30,843.0 MW (15.6 percent) are in the AEP Zone, of which 13,927.8 MW (45.2 percent) are coal fired steam units, 6,990.0 MW (22.7 percent) are combined cycle units and 2,071.0 MW (6.7 percent) are nuclear units.
- Pennsylvania has the most total installed capacity of any PJM state. Of the 197,574.5 MW of installed capacity, 47,265.3 MW (23.9 percent) are in Pennsylvania, of which 9,324.4 MW (19.7 percent) are coal fired steam units, 17,071.5 MW (36.1 percent) are combined cycle units and 8,843.8 MW (18.7 percent) are nuclear units.
- Of the 197,574.5 MW of installed capacity, 71,487.0 MW (36.2 percent) are from units older than 40 years, of which 37,593.2 MW (52.6 percent) are coal fired steam units, 532.0 MW (0.7 percent) are combined cycle units and 15,239.9 MW (21.3 percent) are nuclear units.

#### Generation Retirements[2]

- There are 43,006.2 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 31,089.2 MW (72.3 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 natural gas.
- In 2019, 5,456.3 MW of generation retired. The largest generators that retired in 2019 were the three 830.0 MW Mansfield coal fired steam units owned by FirstEnergy Corporation and located in the American Transmission Systems Inc. (ATSI) Zone. Of the 5,456.3 MW of generation that retired, 2,490.0 MW (45.6 percent) were located in the ATSI Zone.
- As of December 31, 2019, there are 6,178.8 MW of generation that have requested retirement after December 31, 2019, of which 1,278.0 MW (20.7 percent) are located in the APS Zone. Of the APS generation requesting retirement, all 1,278.0 MW (100.0 percent) are coal fired steam units.

#### Generation Queue[3]

- There were 114,953.7 total MW in generation queues, in the status of active, under construction or suspended, at the end of 2018. In 2019, the AE2 and AF1 queue windows closed and the AF2 queue window opened. Combined, these queue windows added 65,829.8 MW to the queue. 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. On December 31, 2019, there were 136,158.4 total MW in generation queues, in the status of active, under construction or suspended, an increase of 21,204.7 MW (18.5 percent).
- 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 December 31, 2019, there were 36,161.4 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).[4] As of December 31, 2019, there were only 96.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.

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

- As of December 31, 2019, 4,838 projects, representing 590,916.9 MW, have entered the queue process since its inception in 1998. Of those, 881 projects, representing 68,989.7 MW, went into service. Of the projects that entered the queue process, 2,684 projects, representing 385,768.8 MW (65.3 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 December 31, 2019, 136,158.4 MW were in generation request queues in the status of active, under construction or suspended. Of the total 136,158.4 MW in the queue, 69,156.5 MW (50.8 percent) have reached at least the system impact study (SIS) milestone and 67,001.9 MW (49.2 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), 34,555.4 MW of new generation in the queue are expected to go into service.

## Regional Transmission Expansion Plan (RTEP)

### Market Efficiency Process

- 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.
- Through December 31, 2019, PJM has completed four market efficiency cycles under Order No. 1000.[5]

### PJM MISO Interregional Market Efficiency Process (IMEP)

- PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion.

### PJM MISO Targeted Market Efficiency Process (TMEP)

- PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects.

### Supplemental Transmission Projects

- Supplemental projects are defined to be "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."[6] Supplemental projects are exempt from the competitive planning process.
- The average number of supplemental projects in each expected in service year increased by 620.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 144 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 supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build the project or to effectively replace the RTEP process.

5 See *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011) (Order No. 1000), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

6 See PJM. "Transmission Construction Status," (Accessed on December 31, 2019) <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. Some Transmission Owners include end of life transmission projects in their Transmission Owner Form 715 Planning Criteria. These projects were exempt from the competitive planning process.[7] On August 30, 2019, the Commission issued an Order Instituting Section 206 Proceeding that removed the proposal window exemption for Form No. 715 Planning Criteria.[8]
- End of life transmission projects should be included in the RTEP process and 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, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[9] In 2019, the PJM Board approved a net change of -$296.3 million in upgrades. As of December 31, 2019, the PJM Board has approved $37.6 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 would help ensure that the process is an open and transparent process that results in the most competitive solutions.
- 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 competitive transmission proposals with binding cost containment proposals compared to proposals from incumbent and nonincumbent transmission companies 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 (CETL) into an LDA and can be offered into capacity auctions as 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, 2019, no QTUs have cleared a BRA.

## 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.[10]
- There were 12,075 transmission outage requests submitted in the first seven months of the 2019/2020 planning period. Of the requested outages, 74.7 percent of the requested outages were planned for less than or equal to five days and 9.9 percent of requested outages were planned for greater than 30 days. Of the requested outages, 48.1 percent were late according to the rules in PJM's Manual 3.

# Recommendations

## Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed.

7 See PJM. Operating Agreement, Schedule 6 § 1.5.8(o).
8 168 FERC ¶ 61,132 at P 13 (2019)..
9 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.
10 See PJM. "PJM Manual 03: Transmission Operations," Rev. 56 (Dec. 5, 2019).

The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[11] (Priority: Low. First reported 2013. Status: Adopted, 2012.)

- 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: Adopted, 2019.)

## Generation Queue

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported 2014. Status: Partially adopted.)
- 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 the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported Q3, 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, 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 increased congestion costs and the risk of project cost increases, in all zones are included and in order to ensure that the correct metrics are used for defining benefits. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, 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 and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (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 included in the RTEP process and should be subject to a transparent, robust and

11 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>.

clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported Q1, 2019. 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.[12] (Priority: Medium. First reported 2015. Status: Not adopted.)

## Transmission Line Ratings

- The MMU recommends that all PJM transmission owners use the same methods to define line ratings, subject to NERC standards and guidelines, subject to review by NERC and approval by FERC. (Priority: Medium. New recommendation. 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.)

12 See the *2015 State of the Market Report for PJM*, Volume 2, Section 12: Generation and Transmission Planning, at p. 463, Cost Allocation Issues.

## Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets.

The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly, whether there is more risk associated with the generation or transmission alternatives, or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The current market efficiency process does exactly the opposite by permitting transmission projects to be approved without competition from generation. The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. The MMU recommends that the market efficiency process be eliminated.

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 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.

If it is retained, 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 definition of benefits should also be reevaluated.

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.

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

# Generation Interconnection Planning

## Existing Generation Mix

Table 12-1 shows the existing PJM capacity by control zone and unit type.[13] As of December 31, 2019, PJM had an installed capacity of 197,574.5 MW, of which 52,667.6 MW (26.7 percent) are coal fired steam units, 49,641.6 MW (25.1 percent) are combined cycle units and 33,452.6 MW (16.9 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, 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 197,574.5 MW of PJM total installed capacity, 30,843.0 MW (15.6 percent) are in the AEP Zone, of which 13,927.8 MW (45.2 percent) are coal fired steam units, 6,990.0 MW (22.7 percent) are combined cycle units and 2,071.0 MW (6.7 percent) are nuclear units.

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

### Table 12-1 Existing PJM capacity: December 31, 2019 (By zone and unit type (MW))[14]

| 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 | 26.0 | 0.0 | 1.6 | 0.0 | 0.0 | 0.0 | 0.0 | 4.0 | 10.6 | 59.4 | 458.9 | 0.0 | 0.0 | 0.0 | 7.5 | 2,014.5 |
| AEP | 6.0 | 6,990.0 | 3,661.2 | 16.2 | 4.8 | 0.0 | 66.0 | 486.9 | 2,071.0 | 0.0 | 0.0 | 20.4 | 14.7 | 13,927.8 | 738.0 | 0.0 | 50.0 | 2,790.0 | 30,843.0 |
| APS | 80.4 | 2,179.0 | 1,223.3 | 0.0 | 2.0 | 0.0 | 0.0 | 129.2 | 0.0 | 29.6 | 0.0 | 18.3 | 55.1 | 5,409.0 | 0.0 | 0.0 | 0.0 | 1,191.5 | 10,317.4 |
| ATSI | 0.0 | 3,150.5 | 958.0 | 653.0 | 6.4 | 0.0 | 0.0 | 0.0 | 2,134.0 | 0.0 | 18.5 | 46.1 | 0.0 | 2,904.0 | 325.0 | 0.0 | 0.0 | 0.0 | 10,195.5 |
| BGE | 0.0 | 0.0 | 500.1 | 228.8 | 0.0 | 0.0 | 0.0 | 0.4 | 1,716.0 | 0.0 | 0.0 | 7.2 | 1.1 | 1,713.0 | 143.5 | 397.0 | 57.0 | 0.0 | 4,764.1 |
| ComEd | 148.5 | 2,621.1 | 6,969.3 | 226.2 | 0.0 | 0.0 | 0.0 | 0.0 | 10,473.5 | 0.0 | 0.0 | 38.3 | 9.0 | 3,840.1 | 1,326.0 | 0.0 | 0.0 | 4,299.9 | 29,951.9 |
| 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 | 56.0 | 0.0 | 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 | 15.0 | 0.0 | 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 | 256.4 | 10.0 | 0.0 | 3,003.0 | 586.3 | 3,581.3 | 0.0 | 39.0 | 106.4 | 1,093.3 | 3,832.6 | 35.0 | 1,586.0 | 368.4 | 208.0 | 27,640.6 |
| DPL | 0.0 | 1,742.5 | 978.2 | 478.2 | 0.0 | 30.0 | 0.0 | 0.0 | 0.0 | 0.0 | 88.0 | 14.1 | 225.4 | 410.0 | 812.0 | 153.0 | 70.0 | 0.0 | 5,001.4 |
| 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 | 225.6 | 0.0 | 0.4 | 400.0 | 0.0 | 0.0 | 0.0 | 0.0 | 16.1 | 303.7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3,919.5 |
| Met-Ed | 0.0 | 2,101.0 | 2.0 | 398.5 | 0.0 | 0.0 | 0.0 | 19.0 | 0.0 | 0.0 | 0.0 | 33.4 | 0.0 | 115.0 | 0.0 | 0.0 | 60.0 | 0.0 | 2,728.9 |
| 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 | 0.0 | 828.0 | 6.0 | 0.0 | 1,070.0 | 572.0 | 4,546.8 | 0.0 | 2.0 | 0.9 | 3.0 | 0.0 | 762.0 | 0.0 | 163.0 | 0.0 | 12,042.7 |
| PENELEC | 28.4 | 1,900.0 | 350.5 | 57.0 | 0.0 | 0.0 | 513.0 | 77.8 | 0.0 | 120.1 | 28.0 | 17.8 | 0.0 | 6,053.5 | 610.0 | 0.0 | 42.0 | 1,098.8 | 10,896.9 |
| Pepco | 0.0 | 1,729.5 | 764.2 | 308.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 11.1 | 2.5 | 2,433.0 | 1,164.1 | 0.0 | 52.0 | 0.0 | 6,464.4 |
| PPL | 20.0 | 5,558.5 | 252.0 | 129.5 | 20.6 | 0.0 | 0.0 | 706.6 | 2,520.0 | 12.0 | 5.0 | 19.7 | 15.0 | 2,590.9 | 2,449.0 | 0.0 | 29.0 | 216.5 | 14,544.3 |
| PSEG | 7.7 | 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 | 219.4 | 0.0 | 3.0 | 0.0 | 179.1 | 0.0 | 9,371.6 |
| XIC | 0.0 | 0.0 | 858.6 | 0.0 | 0.0 | 0.0 | 0.0 | 269.1 | 1,140.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,482.0 | 0.0 | 0.0 | 0.0 | 0.0 | 4,749.7 |
| Total | 351.0 | 49,641.6 | 25,184.2 | 3,902.4 | 49.8 | 32.0 | 5,052.0 | 3,040.6 | 33,452.6 | 161.7 | 218.5 | 384.6 | 2,002.7 | 52,667.6 | 8,414.6 | 2,136.0 | 1,070.5 | 9,812.2 | 197,574.5 |

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 197,574.5 MW of installed capacity, 47,265.3 MW (23.9 percent) are in Pennsylvania, of which 9,324.4 MW (19.7 percent) are coal fired steam units, 17,071.5 MW (36.1 percent) are combined cycle units and 8,843.8 MW (18.7 percent) are nuclear units.

### Table 12-2 Existing PJM capacity: December 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 | 116.3 | 0.0 | 30.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 8.1 | 0.0 | 410.0 | 812.0 | 0.0 | 70.0 | 0.0 | 2,514.4 |
| IL | 148.5 | 2,621.1 | 6,969.3 | 226.2 | 0.0 | 0.0 | 0.0 | 0.0 | 10,473.5 | 0.0 | 0.0 | 38.3 | 9.0 | 3,840.1 | 1,326.0 | 0.0 | 0.0 | 4,299.9 | 29,951.9 |
| 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 | 552.7 | 0.0 | 0.0 | 0.0 | 0.4 | 1,716.0 | 0.0 | 76.0 | 24.3 | 254.1 | 4,386.0 | 1,307.6 | 550.0 | 109.0 | 295.0 | 13,918.1 |
| 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 | 661.5 | 0.0 | 0.0 | 0.0 | 0.0 | 208.0 | 1,367.5 |
| NJ | 47.7 | 7,714.7 | 2,115.0 | 251.6 | 0.0 | 2.0 | 400.0 | 5.0 | 3,493.0 | 0.0 | 4.0 | 41.7 | 582.5 | 458.9 | 3.0 | 0.0 | 179.1 | 7.5 | 15,305.6 |
| OH | 24.0 | 6,627.7 | 4,201.2 | 725.2 | 6.4 | 0.0 | 0.0 | 200.0 | 2,134.0 | 0.0 | 52.5 | 55.4 | 1.1 | 10,793.8 | 372.0 | 0.0 | 0.0 | 766.8 | 25,960.1 |
| PA | 49.9 | 17,071.5 | 1,491.9 | 1,428.0 | 26.6 | 0.0 | 1,583.0 | 1,445.7 | 8,843.8 | 161.7 | 35.0 | 90.1 | 18.0 | 9,324.4 | 3,821.0 | 0.0 | 294.0 | 1,580.7 | 47,265.3 |
| 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 | 591.4 | 12.0 | 0.0 | 3,069.0 | 460.1 | 3,581.3 | 0.0 | 33.0 | 112.4 | 461.8 | 2,827.6 | 495.0 | 1,586.0 | 368.4 | 0.0 | 26,704.9 |
| WV | 60.9 | 0.0 | 1,073.9 | 11.0 | 0.0 | 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 | 858.6 | 0.0 | 0.0 | 0.0 | 0.0 | 269.1 | 1,140.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,482.0 | 0.0 | 0.0 | 0.0 | 0.0 | 4,749.7 |
| Total | 351.0 | 49,641.6 | 25,184.2 | 3,902.4 | 49.8 | 32.0 | 5,052.0 | 3,040.6 | 33,452.6 | 161.7 | 218.5 | 384.6 | 2,002.7 | 52,667.6 | 8,414.6 | 2,136.0 | 1,070.5 | 9,812.2 | 197,574.5 |

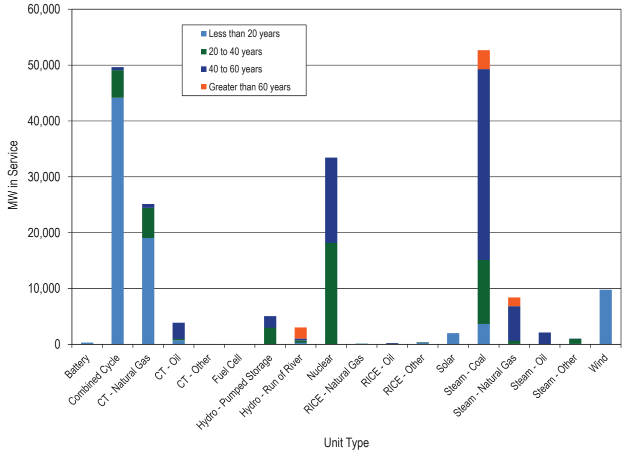
Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of December 31, 2019. Of the 197,574.5 MW of installed capacity, 71,487.0 MW (36.2 percent) are from units older than 40 years, of which 37,593.2 MW (52.6 percent) are coal fired steam units, 532.0 MW (0.7 percent) are combined cycle units and 15,239.9 MW (21.3 percent) are nuclear units.

### Table 12-3 PJM capacity (MW) by unit type and age (years): December 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 | 351.0 | 44,157.1 | 19,021.7 | 740.8 | 43.8 | 32.0 | 0.0 | 297.2 | 0.0 | 149.7 | 20.0 | 315.2 | 2,002.7 | 3,655.0 | 82.0 | 0.0 | 97.4 | 9,812.2 | 80,777.7 |
| 20 to 40 | 0.0 | 4,952.5 | 5,460.3 | 219.2 | 6.0 | 0.0 | 3,003.0 | 427.2 | 18,212.7 | 12.0 | 25.0 | 69.4 | 0.0 | 11,419.4 | 600.0 | 0.0 | 903.1 | 0.0 | 45,309.8 |
| 40 to 60 | 0.0 | 532.0 | 702.2 | 2,942.4 | 0.0 | 0.0 | 2,049.0 | 340.0 | 15,239.9 | 0.0 | 173.5 | 0.0 | 0.0 | 34,206.4 | 6,146.1 | 2,136.0 | 70.0 | 0.0 | 64,537.5 |
| 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 | 3,386.8 | 1,586.5 | 0.0 | 0.0 | 0.0 | 6,949.5 |
| Total | 351.0 | 49,641.6 | 25,184.2 | 3,902.4 | 49.8 | 32.0 | 5,052.0 | 3,040.6 | 33,452.6 | 161.7 | 218.5 | 384.6 | 2,002.7 | 52,667.6 | 8,414.6 | 2,136.0 | 1,070.5 | 9,812.2 | 197,574.5 |

14 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.

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




## Generation Retirements[15 16]

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.[17] 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.[18]

Rules that preserve the Capacity Interconnection 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.[19] 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.[20] 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 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.[21]

## Generation Retirements 2011 through 2024

Table 12-4 shows that as of December 31, 2019, there are 43,006.2 MW of generation that have been, or are planned to be, retired between 2011 and 2024, of which 31,089.2 MW (72.3 percent) are coal fired steam units. Retirements are primarily a result of the inability of coal and other units to compete with efficient combined cycle units burning low cost gas.

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

16 Generation retirements reported in this section do not include external units. Therefore, retirement totals reported in this section may not match totals reported elsewhere in this report where external units are included.

17 See OATT Section V and Attachment M–Appendix § IV.

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

19 See OATT § 230.3.3.

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

21 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>.

## Table 12-4 Summary of PJM unit retirements by unit type (MW): 2011 through 2024

| | 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 | 128.3 | 0.0 | 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 | 240.0 | 0.0 | 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 | 422.0 | 0.0 | 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 | 856.2 | 2.0 | 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 | 65.0 | 6.0 | 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 | 38.0 | 1.6 | 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 | 346.8 | 51.4 | 6.4 | 0.0 | 0.0 | 0.0 | 805.0 | 0.0 | 0.0 | 15.9 | 0.0 | 4,113.8 | 97.0 | 10.0 | 10.0 | 0.0 | 5,456.3 |
| Planned Retirements (January 2020 and later) | 0.0 | 0.0 | 312.5 | 24.0 | 6.0 | 0.0 | 0.0 | 0.0 | 1,777.0 | 0.0 | 13.0 | 0.0 | 0.0 | 3,098.3 | 102.0 | 786.0 | 60.0 | 0.0 | 6,178.8 |
| Total | 41.0 | 425.0 | 2,364.3 | 1,824.9 | 22.0 | 0.0 | 0.5 | 0.0 | 3,196.5 | 0.0 | 57.1 | 49.8 | 0.0 | 31,089.2 | 2,065.5 | 1,658.0 | 202.0 | 10.4 | 43,006.2 |

Table 12-5 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2024, while Table 12-6 shows these retirements by state. Of the 43,006.2 MW of units that has been, or are planned to be, retired between 2011 and 2024, 31,089.2 MW (72.3 percent) are coal fired steam units. These coal fired steam units have an average age of 52.3 years and an average size of 188.4 MW. Over half of the retiring coal fired steam units, 50.4 percent, are located in either Ohio or Pennsylvania.

## Table 12-5 Retirements by unit type: 2011 through 2024

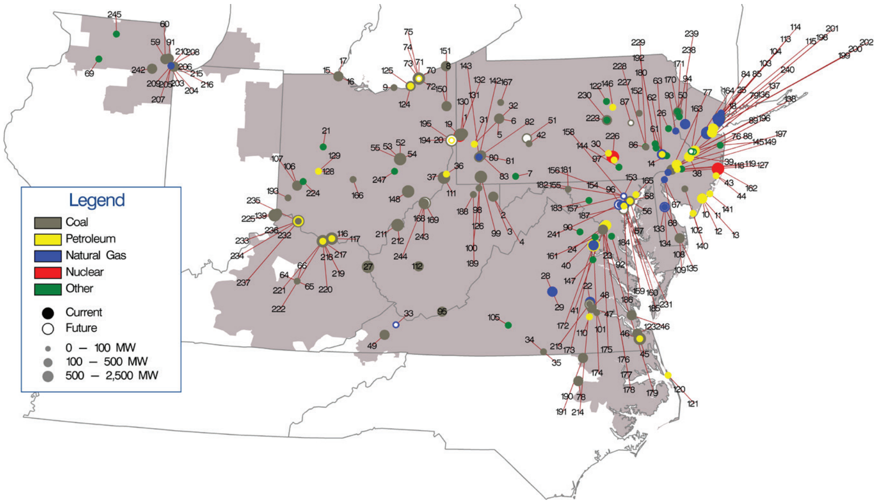
| Unit Type | Number of Units | Avg. Size (MW) | Avg. Age at Retirement (Years) | Total MW | Percent |
|---|---|---|---|---|---|
| Battery | 2 | 20.5 | 7.0 | 41.0 | 0.1% |
| Combined Cycle | 2 | 212.5 | 25.5 | 425.0 | 1.0% |
| Combustion Turbine | 115 | 26.8 | 34.7 | 4,211.2 | 9.8% |
| Natural Gas | 60 | 39.4 | 40.9 | 2,364.3 | 5.5% |
| Oil | 49 | 37.2 | 44.1 | 1,824.9 | 4.2% |
| Other | 6 | 3.7 | 19.2 | 22.0 | 0.1% |
| Fuel Cell | 0 | 0.0 | 0.0 | 0.0 | 0.0% |
| Hydro | 1 | 0.5 | 113.8 | 0.5 | 0.0% |
| Pumped Storage | 1 | 0.5 | 113.8 | 0.5 | 0.0% |
| Run of River | 0 | 0.0 | 0.0 | 0.0 | 0.0% |
| Nuclear | 4 | 799.1 | 43.4 | 3,196.5 | 7.4% |
| RICE | 24 | 4.5 | 28.3 | 106.9 | 0.2% |
| Natural Gas | 0 | 0.0 | 0.0 | 0.0 | 0.0% |
| Oil | 11 | 5.2 | 46.1 | 57.1 | 0.1% |
| Other | 13 | 3.8 | 10.4 | 49.8 | 0.1% |
| Solar | 0 | 0.0 | 0.0 | 0.0 | 0.0% |
| Steam | 196 | 152.1 | 46.0 | 35,014.7 | 81.4% |
| Coal | 165 | 188.4 | 52.3 | 31,089.2 | 72.3% |
| Natural Gas | 18 | 114.8 | 60.8 | 2,065.5 | 4.8% |
| Oil | 6 | 276.3 | 45.7 | 1,658.0 | 3.9% |
| Other | 7 | 28.9 | 25.1 | 202.0 | 0.5% |
| Wind | 1 | 10.4 | 15.6 | 10.4 | 0.0% |
| Total | 345 | 124.7 | 46.1 | 43,006.2 | 100.0% |

## Table 12-6 Retirements (MW) by unit type and state: 2011 through 2024

| 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 | 240.0 | 0.0 | 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 | 104.0 | 1.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.8 | 0.0 | 635.0 | 171.0 | 0.0 | 0.0 | 0.0 | 1,259.9 |
| NC | 0.0 | 0.0 | 0.0 | 31.0 | 0.0 | 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 | 1,040.2 | 6.4 | 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 | 286.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 32.3 | 5.4 | 0.0 | 13,179.4 | 0.0 | 0.0 | 0.0 | 0.0 | 13,543.1 |
| PA | 1.0 | 0.0 | 50.8 | 44.0 | 14.0 | 0.0 | 0.0 | 0.0 | 2,582.0 | 0.0 | 13.9 | 13.0 | 0.0 | 4,844.3 | 283.0 | 176.0 | 109.0 | 10.4 | 8,141.4 |
| VA | 0.0 | 267.0 | 80.0 | 79.7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.9 | 8.4 | 0.0 | 2,739.0 | 543.0 | 786.0 | 83.0 | 0.0 | 4,589.0 |
| 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 | 3,969.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3,969.0 |
| Total | 41.0 | 425.0 | 2,364.3 | 1,824.9 | 22.0 | 0.0 | 0.5 | 0.0 | 3,196.5 | 0.0 | 57.1 | 49.8 | 0.0 | 31,089.2 | 2,065.5 | 1,658.0 | 202.0 | 10.4 | 43,006.2 |

Figure 12-2 is a map of unit retirements between 2011 and 2024, with a mapping to unit names in Table 12-7.

## Figure 12-2 Map of PJM unit retirements: 2011 through 2024




## Table 12-7 Unit identification for map of PJM unit retirements: 2011 through 2024

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

## Current Year Generation Retirements

Table 12-8 shows that in 2019, 5,456.3 MW of generation retired. The largest generators that retired in 2019 were the three 830.0 MW Mansfield coal fired steam units owned by FirstEnergy Corporation and located in the American Transmission Systems Incorporated (ATSI) Zone. Of the 5,456.3 MW of generation that retired, 2,490.0 MW (45.6 percent) were located in the ATSI Zone.

### Table 12-8 Unit deactivations: 2019

| 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 |
| Dominion Resources, Inc. | Yorktown 1 | 164.0 | Steam-Coal | Dominion | 60.2 | 08-Mar-19 |
| Dominion Resources, Inc. | Yorktown 2 | 159.0 | Steam-Coal | Dominion | 61.7 | 08-Mar-19 |
| Exelon Corporation | Riverside 7 | 19.0 | CT-Oil | BGE | 48.6 | 14-Mar-19 |
| Ares Management LP | Edgecomb NUG (aka Edgecomb Rocky 1-2) | 115.5 | Steam-Coal | Dominion | 28.5 | 22-Apr-19 |
| Rockland Capital Energy Investments, LLC | BL England 2 | 155.0 | Steam-Coal | AECO | 54.5 | 30-Apr-19 |
| Dominion Resources, Inc. | Chesapeake GT2 | 12.4 | CT-Oil | Dominion | 50.3 | 31-May-19 |
| American Electric Power Company, Inc. | Conesville 5 | 400.0 | Steam-Coal | AEP | 42.6 | 01-Jun-19 |
| American Electric Power Company, Inc. | Conesville 6 | 400.0 | Steam-Coal | AEP | 41.0 | 01-Jun-19 |
| Covanta Holding Corporation | Warren County NUG | 10.0 | Steam-Other | JCPL | 31.4 | 01-Jun-19 |
| Exelon Corporation | Gould Street Generation Station | 97.0 | Steam-Natural Gas | BGE | 66.5 | 01-Jun-19 |
| Starwood Capital Group LLC | MH50 Markus Hook Co-gen | 50.8 | CT-Natural Gas | PECO | 31.6 | 01-Jun-19 |
| Novi Energy LLC | Hopewell James River Cogeneration | 89.0 | Steam-Coal | Dominion | 35.1 | 25-Jun-19 |
| Exelon Corporation | Bethlehem Renewable Energy Generator (Landfill) | 5.0 | RICE-Other | PPL | 11.5 | 31-Aug-19 |
| Kimberly-Clark Corporation | Kimberly Clark Generator | 3.3 | Steam-Coal | PECO | 33.7 | 04-Sep-19 |
| Northern Star Generation Services, Llc | Cambria CoGen | 88.0 | Steam-Coal | PENELEC | 28.6 | 17-Sep-19 |
| Exelon Corporation | Three Mile Island Unit 1 Nuclear Generating Station | 805.0 | Nuclear | Met-Ed | 45.5 | 20-Sep-19 |
| NextEra Energy, Inc. | Monmouth NUG landfill | 6.4 | CT-Other | JCPL | 21.8 | 27-Sep-19 |
| FirstEnergy Corp. | Mansfield 3 | 830.0 | Steam-Coal | ATSI | 39.2 | 07-Nov-19 |
| Public Service Enterprise Group Incorporated | Occoquan 1 LF | 6.4 | RICE-Other | Dominion | 7.4 | 07-Nov-19 |
| Exelon Corporation | Riverside 8 | 20.0 | CT-Oil | BGE | 49.3 | 01-Dec-19 |
| Exelon Corporation | Southeast Chicago CT11 | 37.0 | CT-Natural Gas | ComEd | 17.2 | 17-Dec-19 |
| Exelon Corporation | Southeast Chicago CT12 | 37.0 | CT-Natural Gas | ComEd | 17.2 | 17-Dec-19 |
| Exelon Corporation | Southeast Chicago CT5 | 37.0 | CT-Natural Gas | ComEd | 17.2 | 17-Dec-19 |
| Exelon Corporation | Southeast Chicago CT6 | 37.0 | CT-Natural Gas | ComEd | 17.2 | 17-Dec-19 |
| Exelon Corporation | Southeast Chicago CT7 | 37.0 | CT-Natural Gas | ComEd | 17.2 | 17-Dec-19 |
| Exelon Corporation | Southeast Chicago CT8 | 37.0 | CT-Natural Gas | ComEd | 17.2 | 17-Dec-19 |
| Exelon Corporation | Southeast Chicago GT10 | 37.0 | CT-Natural Gas | ComEd | 17.2 | 17-Dec-19 |
| Exelon Corporation | Southeast Chicago GT9 | 37.0 | CT-Natural Gas | ComEd | 17.2 | 17-Dec-19 |
| FirstEnergy Corp. | MEA NUG (WVU) | 50.0 | Steam-Coal | APS | 29.7 | 30-Dec-19 |
| DTE Energy Company | Bellefontaine Landfill Generating Station | 4.5 | RICE-Other | DAY | 10.8 | 31-Dec-19 |
| Total | | 5,456.3 | | | | |

## Planned Generation Retirements

Table 12-9 shows that, as of December 31, 2019, there are 6,178.8 MW of generation that have requested retirement after December 31, 2019, of which 1,278.0 MW (20.7 percent) are located in the APS Zone. Of the APS generation requesting retirement, all 1,278.0 MW (100.0 percent) are coal fired steam units.

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

| Company | Unit Name | ICAP (MW) | Unit Type | Zone Name | Projected Deactivation Date |
|---|---|---|---|---|---|
| Ares Management LP | Spruance NUG1 (aka Spruance 1 Rich 1-2) | 115.5 | Steam-Coal | Dominion | 12-Jan-20 |
| FirstEnergy Corp. | Eastlake 6 | 24.0 | CT-Oil | ATSI | 18-Feb-20 |
| Macquarie Group Limited | FRACKVILLE WHEELABRATOR 1 | 43.0 | Steam-Coal | PPL | 03-Mar-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 |
| FirstEnergy Corp. | Beaver Valley U1 Nuclear Generating Unit | 892.0 | Nuclear | DLCO | 31-May-21 |
| Dominion Resources, Inc. | Possum Point 5 | 786.0 | Steam-Oil | Dominion | 31-May-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 |
| LS Power Equity Partners, L.P. | Buchanan 1-2 | 80.0 | CT-Natural Gas | AEP | 01-Jun-23 |
| Total | | 6,178.8 | | | |

## 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.[22] 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 AE2 began on October 1, 2018 and closed on March 31, 2019. Queue AF1 began on April 1, 2019 and closed on September 30, 2019. Queue AF2 opened on October 1, 2019 and will close on March 31, 2020.

22 See OATT Parts IV & VI.

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.[23] 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.[24]

The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result.[25] 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. The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service.

### Table 12-10 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 |

23 See PJM. "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 13 (August 23, 2018).
24 PJM does not track the duration of suspensions or PJM termination of projects.
25 See *PJM Interconnection, L.L.C.*, Docket No. ER12-1177 (Feb. 29, 2012).

## Planned Generation Additions

Expected net revenues provide incentives to build new generation to serve PJM markets. The amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM energy, capacity and ancillary service markets. On December 31, 2019, 136,158.4 MW 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.[26]

There were 114,953.7 total MW in generation queues, in the status of active, under construction or suspended, at the end of 2018. In 2019, the AE2 and AF1 queue windows closed and the AF2 queue window opened. Combined, these queue windows added 65,829.8 MW to the queue. 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. On December 31, 2019, there were 136,158.4 total MW in generation queues, in the status of active, under construction or suspended, an increase of 21,204.7 MW (18.5 percent). Table 12-11 shows MW in queues by expected completion year and MW changes in the queue between December 31, 2018, and December 31, 2019, for ongoing projects, i.e. projects with the status active, under construction or suspended.[27]

### Table 12-11 Queue comparison by expected completion year (MW): December 31, 2018 and December 31, 2019[28]

| | | | Year Change | |
|---|---|---|---|---|
| Year | As of 12/31/2018 | As of 12/31/2019 | MW | Percent |
| 2008 | 0.0 | 0.0 | 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 | 40.0 | (62.5) | (61.0%) |
| 2012 | 59.6 | 20.6 | (39.0) | (65.4%) |
| 2013 | 20.0 | 20.0 | 0.0 | 0.0% |
| 2014 | 25.0 | 10.0 | (15.0) | (60.0%) |
| 2015 | 398.8 | 201.3 | (197.5) | (49.5%) |
| 2016 | 638.5 | 278.9 | (359.6) | (56.3%) |
| 2017 | 2,772.4 | 1,482.8 | (1,289.6) | (46.5%) |
| 2018 | 9,444.5 | 3,735.2 | (5,709.3) | (60.5%) |
| 2019 | 14,446.2 | 13,463.6 | (982.5) | (6.8%) |
| 2020 | 21,958.7 | 18,901.3 | (3,057.4) | (13.9%) |
| 2021 | 2,128.6 | 33,232.2 | 31,103.7 | 1,461.3% |
| 2022 | 1,200.9 | 37,607.0 | 36,406.1 | 3,031.6% |
| 2023 | 0.0 | 13,087.8 | 13,087.8 | 0.0% |
| 2024 | 0.0 | 7,385.3 | 7,385.3 | 0.0% |
| 2025 | 0.0 | 3,766.9 | 3,766.9 | 0.0% |
| 2026 | 0.0 | 1,325.2 | 1,325.2 | 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 | 53,195.6 | 136,158.4 | 82,962.8 | 156.0% |

Table 12-12 shows the project status changes in more detail and how scheduled queue capacity has changed between December 31, 2018, and December 31, 2019. For example, 117,971.1 MW entered the queue in 2019. Of those 117,971.1 MW, 34,797.8 MW have been withdrawn. Of the total 71,160.4 MW marked as active on December 31, 2018, 23,446.0 MW were withdrawn, 5,652.6 MW were suspended, 5,801.6 MW started construction, and 1,403.9 MW went into service by December 31, 2019. Analysis of projects that were suspended on December 31, 2018 show that 1,116.9 MW came out of suspension and are now active as of December 31, 2019.

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

| | | Status at 12/31/2019 | | | | |
|---|---|---|---|---|---|---|
| Status at 12/31/2018 | Total at 12/31/2018 | Active | In Service | Under Construction | Suspended | Withdrawn |
| (Entered during 2019) | 0.0 | 82,909.1 | 210.5 | 1.1 | 52.6 | 34,797.8 |
| Active | 71,160.4 | 34,856.3 | 1,403.9 | 5,801.6 | 5,652.6 | 23,446.0 |
| In Service | 51,580.8 | 0.0 | 51,579.8 | 0.0 | 0.0 | 1.0 |
| Under Construction | 18,593.4 | 359.3 | 15,635.7 | 1,466.0 | 150.0 | 982.4 |
| Suspended | 8,763.7 | 1,116.9 | 159.9 | 1,866.8 | 1,926.1 | 3,694.0 |
| Withdrawn | 322,847.7 | 0.0 | 0.0 | 0.0 | 0.0 | 322,847.7 |
| Total | 472,945.8 | 119,241.6 | 68,989.7 | 9,135.5 | 7,781.3 | 385,768.8 |

26 See "*PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years*," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_Delivery_Years_20190912.pdf>.

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

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

On December 31, 2019, 136,158.4 MW of capacity were in generation request queues in the status of active, suspended or under construction. Table 12-13 shows each status by unit type. Of the 119,241.6 MW in the status of Active on December 31, 2019, 17,972.4 MW (15.1 percent) were combined cycle projects. Of the 9,135.5 MW in the status of under construction, 5,774.3 MW (63.2 percent) were combined cycle projects.

### Table 12-13 Current project status (MW) by unit type: December 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 | 6,215.2 | 17,972.4 | 5,982.5 | 27.0 | 0.0 | 3.0 | 700.0 | 66.0 | 123.5 | 40.0 | 0.0 | 0.8 | 59,698.4 | 60.0 | 64.0 | 0.0 | 40.0 | 28,248.8 | 119,241.6 |
| Suspended | 42.5 | 5,804.1 | 230.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 39.8 | 0.0 | 0.0 | 649.7 | 0.0 | 0.0 | 0.0 | 16.0 | 999.3 | 7,781.3 |
| Under Construction | 4.5 | 5,774.3 | 253.0 | 0.0 | 0.0 | 0.0 | 0.0 | 22.7 | 44.0 | 1.3 | 4.0 | 0.0 | 866.2 | 36.0 | 0.0 | 0.0 | 62.5 | 2,067.0 | 9,135.5 |
| Total | 6,262.1 | 29,550.8 | 6,465.5 | 27.0 | 0.0 | 3.0 | 700.0 | 88.7 | 167.5 | 81.1 | 4.0 | 0.8 | 61,214.3 | 96.0 | 64.0 | 0.0 | 118.5 | 31,315.0 | 136,158.4 |

A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units enter the queue and coal fired steam units retire. As of December 31, 2019, there were 36,161.1 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 December 31, 2019, there were only 96.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.

There are 3,098.3 MW of coal fired steam capacity and 414.5 MW of natural gas capacity slated for deactivation between January 1, 2020, and December 31, 2024 (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 December 31, 2019, there are 136,158.4 MW of capacity in queues that are not yet in service or withdrawn, of which 5.7 percent are suspended, 6.7 percent are under construction and 87.6 percent have not begun construction.

## Table 12-14 Capacity in PJM queues (MW): December 31, 2019[29]

| 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 | 1,890.2 | 0.0 | 0.0 | 5,466.8 | 7,357.0 |
| P Expired 31-Jan-06 | 0.0 | 3,227.8 | 62.5 | 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 | 0.0 | 1,892.5 | 0.0 | 0.0 | 20,708.9 | 22,601.4 |
| 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 | 218.9 | 0.0 | 0.0 | 7,937.8 | 8,156.7 |
| U2 Expired 31-Jul-08 | 0.0 | 267.5 | 560.0 | 0.0 | 16,218.6 | 17,046.1 |
| U3 Expired 31-Oct-08 | 100.0 | 333.0 | 0.0 | 0.0 | 2,535.6 | 2,968.6 |
| U4 Expired 31-Jan-09 | 200.0 | 85.2 | 0.0 | 0.0 | 4,745.0 | 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 | 20.0 | 912.0 | 200.0 | 0.0 | 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 | 0.0 | 553.9 | 13.5 | 0.0 | 5,139.5 | 5,706.9 |
| 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 | 499.9 | 37.7 | 100.0 | 8,573.2 | 9,210.8 |
| W4 Expired 31-Jan-11 | 0.0 | 1,101.8 | 367.9 | 0.0 | 4,152.6 | 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 | 0.0 | 5,578.4 | 9,310.2 |
| 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 | 0.0 | 1,795.5 | 0.0 | 72.0 | 6,207.7 | 8,075.2 |
| Y2 Expired 31-Oct-12 | 0.0 | 1,452.7 | 4.5 | 200.0 | 9,636.5 | 11,293.7 |
| Y3 Expired 30-Apr-13 | 0.0 | 1,425.5 | 205.0 | 0.0 | 4,609.2 | 6,239.6 |
| Z1 Expired 31-Oct-13 | 1,013.3 | 2,998.0 | 76.5 | 0.0 | 4,037.0 | 8,124.8 |
| Z2 Expired 30-Apr-14 | 0.0 | 2,863.0 | 200.0 | 43.0 | 2,994.8 | 6,100.8 |
| AA1 Expired 31-Oct-14 | 828.0 | 2,372.7 | 2,456.3 | 311.7 | 6,100.3 | 12,068.9 |
| AA2 Expired 30-Apr-15 | 2,784.2 | 1,100.7 | 1,719.9 | 1,276.0 | 9,185.5 | 16,066.3 |
| AB1 Expired 31-Oct-15 | 7,613.1 | 1,076.5 | 259.3 | 1,236.2 | 10,265.8 | 20,450.9 |
| AB2 Expired 31-Mar-16 | 4,110.9 | 207.5 | 1,372.9 | 1,329.8 | 8,196.3 | 15,217.4 |
| AC1 Expired 30-Sep-16 | 7,760.9 | 395.7 | 864.9 | 1,796.0 | 9,254.9 | 20,072.3 |
| AC2 Expired 30-Apr-17 | 3,981.0 | 111.0 | 205.6 | 42.1 | 8,262.0 | 12,601.6 |
| AD1 Expired 30-Sep-17 | 7,126.9 | 26.7 | 154.3 | 55.0 | 3,935.9 | 11,298.8 |
| AD2 Expired 31-Mar-18 | 8,658.9 | 210.5 | 0.0 | 45.0 | 11,485.9 | 20,400.3 |
| AE1 Expired 30-Sep-18 | 18,424.7 | 0.0 | 1.1 | 7.6 | 15,494.1 | 33,927.6 |
| AE2 Expired 31-Mar-19 | 26,625.2 | 0.0 | 0.0 | 0.0 | 7,541.3 | 34,166.5 |
| AF1 Expired 30-Sep-19 | 27,787.9 | 0.0 | 0.0 | 0.0 | 1,827.9 | 29,615.8 |
| AF2 Through 31-Mar-20 | 2,047.5 | 0.0 | 0.0 | 0.0 | 0.0 | 2,047.5 |
| Total | 119,241.6 | 68,989.7 | 9,135.5 | 7,781.3 | 385,768.8 | 590,916.9 |

29 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 December 31, 2019, 136,158.4 MW of capacity were in generation request queues for construction through 2029.[30] 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): December 31, 2019[31]

| 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 | 900.0 | 582.6 | 230.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 719.2 | 0.0 | 0.0 | 0.0 | 0.0 | 3,939.6 | 6,371.4 | 0.0 |
| | DPL | 64.5 | 451.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,715.0 | 0.0 | 0.0 | 0.0 | 0.0 | 679.1 | 2,909.6 | 102.0 |
| | JCPL | 750.2 | 140.0 | 221.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 297.5 | 0.0 | 0.0 | 0.0 | 0.0 | 4,759.2 | 6,167.9 | 0.0 |
| | PECO | 20.0 | 102.0 | 29.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 94.0 | 0.0 | 4.0 | 0.0 | 29.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 278.8 | 66.0 |
| | PSEG | 402.0 | 882.6 | 675.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 68.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,027.6 | 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 | 2,136.7 | 2,158.2 | 1,155.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 94.0 | 0.0 | 4.0 | 0.0 | 2,889.3 | 0.0 | 0.0 | 0.0 | 0.0 | 9,377.9 | 17,815.2 | 168.0 |
| SWMAAC | BGE | 200.0 | 0.0 | 144.6 | 14.0 | 0.0 | 0.0 | 0.0 | 0.0 | 45.5 | 1.3 | 0.0 | 0.0 | 40.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 445.4 | 367.5 |
| | 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 | 190.7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,368.3 | 0.0 |
| | SWMAAC Total | 200.0 | 1,177.6 | 144.6 | 14.0 | 0.0 | 0.0 | 0.0 | 0.0 | 45.5 | 1.3 | 0.0 | 0.0 | 230.7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,813.7 | 367.5 |
| WMAAC | Met-Ed | 40.0 | 113.9 | 13.5 | 7.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,055.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,230.2 | 0.0 |
| | PENELEC | 172.0 | 248.0 | 585.5 | 0.0 | 0.0 | 3.0 | 0.0 | 0.0 | 0.0 | 39.9 | 0.0 | 0.0 | 4,161.2 | 0.0 | 0.0 | 0.0 | 0.0 | 310.2 | 5,519.8 | 110.0 |
| | PPL | 250.0 | 1,944.8 | 0.0 | 0.0 | 0.0 | 0.0 | 700.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,031.3 | 0.0 | 0.0 | 0.0 | 16.0 | 430.1 | 4,372.2 | 43.0 |
| | WMAAC Total | 462.0 | 2,306.7 | 599.0 | 7.5 | 0.0 | 3.0 | 700.0 | 0.0 | 0.0 | 39.9 | 0.0 | 0.0 | 6,247.8 | 0.0 | 0.0 | 0.0 | 16.0 | 740.3 | 11,122.2 | 153.0 |
| Non-MAAC | AEP | 1,203.6 | 6,071.0 | 567.5 | 0.0 | 0.0 | 0.0 | 0.0 | 51.0 | 28.0 | 0.0 | 0.0 | 0.8 | 17,669.9 | 76.0 | 0.0 | 0.0 | 40.0 | 5,887.0 | 31,594.8 | 856.8 |
| | APS | 404.0 | 5,589.7 | 112.0 | 0.0 | 0.0 | 0.0 | 0.0 | 15.0 | 0.0 | 39.9 | 0.0 | 0.0 | 2,426.4 | 0.0 | 0.0 | 0.0 | 0.0 | 1,109.4 | 9,696.4 | 1,278.0 |
| | ATSI | 20.3 | 4,635.0 | 116.0 | 5.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,520.8 | 0.0 | 0.0 | 0.0 | 0.0 | 816.1 | 8,113.7 | 677.0 |
| | ComEd | 426.3 | 3,712.6 | 1,239.2 | 0.0 | 0.0 | 0.0 | 0.0 | 22.7 | 0.0 | 0.0 | 0.0 | 0.0 | 4,404.5 | 0.0 | 64.0 | 0.0 | 0.0 | 7,955.2 | 17,824.4 | 0.0 |
| | DAY | 109.9 | 1,150.0 | 127.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,564.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3,951.6 | 0.0 |
| | DEOK | 72.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 559.9 | 20.0 | 0.0 | 0.0 | 0.0 | 0.0 | 652.1 | 0.0 |
| | DLCO | 0.0 | 0.0 | 234.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 54.2 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 288.6 | 1,777.0 |
| | Dominion | 1,227.1 | 2,750.0 | 2,170.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 18,961.5 | 0.0 | 0.0 | 0.0 | 62.5 | 5,429.2 | 30,600.6 | 901.5 |
| | EKPC | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,685.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,685.0 | 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 | 3,463.4 | 23,908.3 | 4,566.9 | 5.5 | 0.0 | 0.0 | 0.0 | 88.7 | 28.0 | 39.9 | 0.0 | 0.8 | 51,846.4 | 96.0 | 64.0 | 0.0 | 102.5 | 21,196.8 | 105,407.3 | 5,490.3 |
| | Total | 6,262.1 | 29,550.8 | 6,465.5 | 27.0 | 0.0 | 3.0 | 700.0 | 88.7 | 167.5 | 81.1 | 4.0 | 0.8 | 61,214.3 | 96.0 | 64.0 | 0.0 | 118.5 | 31,315.0 | 136,158.4 | 6,178.8 |

## 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.[32] 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 2,684 projects withdrawn, 1,337 (49.8 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 2,684 projects withdrawn, 526 (19.6 percent) were withdrawn after the completion of a Construction Service Agreement.

30 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 31,315.0 MW of wind resources and 61,214.3 MW of solar resources, using the average derate factors, the 136,158.4 MW currently under construction, suspended or active in the queue would be reduced to 77,289.1 MW.

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

32 See PJM. "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 46 (Aug. 28, 2019).

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

| Milestone Completed | Projects Withdrawn | Percent | Average Days | Maximum Days |
|---|---|---|---|---|
| Never Started | 469 | 17.5% | 442 | 1,580 |
| Feasibility Study | 868 | 32.3% | 279 | 1,633 |
| System Impact Study | 532 | 19.8% | 739 | 3,248 |
| Facilities Study | 289 | 10.8% | 1,084 | 3,810 |
| Construction Service Agreement (CSA) or beyond | 526 | 19.6% | 1,336 | 4,816 |
| Total | 2,684 | 100.0% | | |

## Average Time in Queue

Table 12-17 shows the time spent at various stages in the queue process and the completion time for the studies performed. For completed projects, there is an average time of 1,052 days, or 2.9 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 624 days, or 1.7 years, between entering a queue and withdrawing.

**Table 12-17 Project queue times by status (days): December 31, 2019[33]**

| Status | Average (Days) | Standard Deviation | Minimum | Maximum |
|---|---|---|---|---|
| Active | 614 | 599 | 7 | 5,481 |
| In-Service | 1,052 | 765 | 0 | 4,986 |
| Suspended | 1,759 | 911 | 550 | 4,759 |
| Under Construction | 2,061 | 1,078 | 463 | 5,251 |
| Withdrawn | 624 | 713 | 0 | 4,682 |

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 1,273 projects in the queue as of December 31, 2019, 303 (23.8 percent) had a completed feasibility study and 280 (22.0 percent) had a completed construction service agreement.

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

| Milestone Reached | Number of Projects | Percent of Total Projects | Average Days | Maximum Days |
|---|---|---|---|---|
| Under Review | 360 | 28.3% | 124 | 656 |
| Feasibility Study | 303 | 23.8% | 434 | 1,341 |
| System Impact Study | 302 | 23.7% | 848 | 4,110 |
| Facilities Study | 28 | 2.2% | 1,442 | 3,918 |
| Construction Service Agreement (CSA) or beyond | 280 | 22.0% | 1,462 | 5,572 |
| Total | 1,273 | 100.0% | | |

## Completion Rates

The probability of a project going into service increases as each step of the planning process is completed.

Table 12-19 shows the historic completion rates (MW energy) by unit type for projects that have completed the system impact study (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, 17.3 percent of the queued MW has gone into service. The completion rate for wind projects increases to 32.0 percent when wind projects complete the facility study agreement and further increases to 48.9 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 has gone into service.

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

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

| Unit Type | Completion Rate (SIS) | Completion Rate (FSA) | Completion Rate (CSA) | Completion Rate (ALL) |
|---|---|---|---|---|
| Battery | 25.4% | 41.3% | 50.7% | 3.0% |
| CC | 33.1% | 52.2% | 83.6% | 13.6% |
| CT - Natural Gas | 77.0% | 83.6% | 87.6% | 44.3% |
| CT - Oil | 35.6% | 60.2% | 90.8% | 25.0% |
| CT - Other | 12.3% | 18.6% | 29.5% | 10.7% |
| Fuel Cell | 30.6% | 31.6% | 31.6% | 17.1% |
| Hydro - Pumped Storage | 100.0% | 100.0% | 100.0% | 24.5% |
| Hydro - Run of River | 43.7% | 62.3% | 69.1% | 21.6% |
| Nuclear | 34.8% | 41.7% | 51.1% | 28.6% |
| RICE - Natural Gas | 35.8% | 50.4% | 56.8% | 26.4% |
| RICE - Oil | 30.6% | 55.9% | 55.9% | 23.8% |
| RICE - Other | 89.0% | 91.4% | 92.0% | 77.9% |
| Solar | 15.1% | 30.7% | 38.7% | 1.8% |
| Steam - Coal | 13.5% | 25.2% | 37.3% | 6.1% |
| Steam - Natural Gas | 90.4% | 90.4% | 90.4% | 84.5% |
| Steam - Oil | 0.0% | 0.0% | 0.0% | 0.0% |
| Steam - Other | 27.9% | 37.2% | 45.2% | 23.5% |
| Wind | 17.3% | 32.0% | 48.9% | 7.9% |

On December 31, 2019, 136,158.4 MW of capacity were in generation request queues in the status of active, under construction or suspended. Of the total 136,158.4 MW in the queue, 69,156.5 MW (50.8 percent) have reached at least the SIS milestone and 67,001.9 MW (49.2 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), 34,555.4 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 2,186 projects entered from January 2015 through December 2019, 1,841 projects, 84.2 percent, were renewable. Of the 683 projects entered in 2019, 634 projects, 92.8 percent, were renewable.

Table 12-20 Number of projects entered in the queue: December 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 | 634 | 49 | 683 |
| Total | 70 | 3,255 | 1,513 | 4,838 |

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 86.4 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: December 31, 2019

| Fuel Group | Number of Projects | Percent of Projects | MW | Percent MW |
|---|---|---|---|---|
| Nuclear | 9 | 0.7% | 167.5 | 0.1% |
| Renewable | 1,100 | 86.4% | 99,583.2 | 73.1% |
| Traditional | 164 | 12.9% | 36,407.7 | 26.7% |
| Total | 1,273 | 100.0% | 136,158.4 | 100.0% |

## Queue Analysis by Unit Type and Project Classification

Table 12-22 shows the current status of all generation queue projects by unit type and project classification from January 1, 1997, through December 31, 2019. As of December 31, 2019, 4,838 projects, representing 590,916.9 MW, have entered the queue process since its inception. Of those, 881 projects, representing 68,989.7 MW, went into service. Of the projects that entered the queue process, 2,684 projects, representing 385,768.8 MW (65.3 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 3,918 projects have been classified as new generation and 920 projects have been classified as upgrades. Wind, solar and natural gas projects have accounted for 3,870 projects, or 80.0 percent, of all 4,838 generation queue projects.

### Table 12-22 Status of all generation queue projects: 1997 through 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 | 61 | 49 | 10 | 25 | 3 | 0 | 10 | 2 | 10 | 0 | 55 | 141 | 8 | 5 | 0 | 4 | 83 | 487 |
| | Upgrade | 5 | 92 | 93 | 15 | 5 | 0 | 3 | 18 | 41 | 9 | 1 | 15 | 19 | 54 | 9 | 0 | 7 | 8 | 394 |
| Under Construction | New Generation | 1 | 6 | 1 | 0 | 0 | 0 | 0 | 2 | 0 | 1 | 0 | 0 | 22 | 0 | 0 | 0 | 0 | 12 | 45 |
| | Upgrade | 0 | 11 | 2 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 2 | 1 | 0 | 0 | 1 | 2 | 21 |
| Suspended | New Generation | 5 | 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 24 | 0 | 0 | 0 | 1 | 9 | 46 |
| | Upgrade | 2 | 5 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 1 | 12 |
| Withdrawn | New Generation | 139 | 422 | 24 | 9 | 81 | 26 | 2 | 39 | 9 | 24 | 12 | 16 | 1,122 | 55 | 1 | 0 | 33 | 429 | 2,443 |
| | Upgrade | 16 | 86 | 12 | 13 | 13 | 2 | 0 | 5 | 9 | 0 | 2 | 3 | 37 | 14 | 0 | 0 | 2 | 27 | 241 |
| Active | New Generation | 77 | 22 | 13 | 1 | 0 | 0 | 2 | 1 | 1 | 2 | 0 | 0 | 694 | 0 | 0 | 0 | 0 | 84 | 897 |
| | Upgrade | 45 | 28 | 44 | 8 | 0 | 1 | 0 | 2 | 7 | 0 | 0 | 1 | 96 | 4 | 1 | 0 | 1 | 14 | 252 |
| Total Projects | New Generation | 243 | 516 | 87 | 20 | 106 | 29 | 4 | 52 | 12 | 39 | 12 | 71 | 2,003 | 63 | 6 | 0 | 38 | 617 | 3,918 |
| | Upgrade | 68 | 222 | 153 | 36 | 18 | 3 | 3 | 25 | 58 | 9 | 4 | 19 | 156 | 73 | 10 | 0 | 11 | 52 | 920 |

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, 72.0 percent of all hydro run of river projects classified as upgrades are currently in service in PJM, 20.0 percent of hydro run of river upgrades were withdrawn and 8.0 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: 1997 through 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 | 8.6% | 11.8% | 56.3% | 50.0% | 23.6% | 10.3% | 0.0% | 19.2% | 16.7% | 25.6% | 0.0% | 77.5% | 7.0% | 12.7% | 83.3% | 0.0% | 10.5% | 13.5% | 12.4% |
| | Upgrade | 7.4% | 41.4% | 60.8% | 41.7% | 27.8% | 0.0% | 100.0% | 72.0% | 70.7% | 100.0% | 25.0% | 78.9% | 12.2% | 74.0% | 90.0% | 0.0% | 63.6% | 15.4% | 42.8% |
| Under Construction | New Generation | 0.4% | 1.2% | 1.1% | 0.0% | 0.0% | 0.0% | 0.0% | 3.8% | 0.0% | 2.6% | 0.0% | 0.0% | 1.1% | 0.0% | 0.0% | 0.0% | 0.0% | 1.9% | 1.1% |
| | Upgrade | 0.0% | 5.0% | 1.3% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.7% | 0.0% | 25.0% | 0.0% | 1.3% | 1.4% | 0.0% | 0.0% | 9.1% | 3.8% | 2.3% |
| Suspended | New Generation | 2.1% | 1.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 5.1% | 0.0% | 0.0% | 1.2% | 0.0% | 0.0% | 0.0% | 2.6% | 1.5% | 1.2% |
| | Upgrade | 2.9% | 2.3% | 1.3% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.3% | 0.0% | 0.0% | 0.0% | 0.0% | 1.9% | 1.3% |
| Withdrawn | New Generation | 57.2% | 81.8% | 27.6% | 45.0% | 76.4% | 89.7% | 50.0% | 75.0% | 75.0% | 61.5% | 100.0% | 22.5% | 56.0% | 87.3% | 16.7% | 0.0% | 86.8% | 69.5% | 62.4% |
| | Upgrade | 23.5% | 38.7% | 7.8% | 36.1% | 72.2% | 66.7% | 0.0% | 20.0% | 15.5% | 0.0% | 50.0% | 15.8% | 23.7% | 19.2% | 0.0% | 0.0% | 18.2% | 51.9% | 26.2% |
| Active | New Generation | 31.7% | 4.3% | 14.9% | 5.0% | 0.0% | 0.0% | 50.0% | 1.9% | 8.3% | 5.1% | 0.0% | 0.0% | 34.6% | 0.0% | 0.0% | 0.0% | 0.0% | 13.6% | 22.9% |
| | Upgrade | 66.2% | 12.6% | 28.8% | 22.2% | 0.0% | 33.3% | 0.0% | 8.0% | 12.1% | 0.0% | 0.0% | 5.3% | 61.5% | 5.5% | 10.0% | 0.0% | 9.1% | 26.9% | 27.4% |

Table 12-24 shows the nameplate generating capacity of projects in the PJM generation queue by technology type and project classification. For example, the 429 new generation wind projects that have been withdrawn from the queue as of December 31, 2019, (as shown in Table 12-22) constitute 73,474.7 MW of nameplate capacity. The 422 new generation and upgrade combined cycle projects that have been withdrawn in the same time period constitute 208,752.2 MW of nameplate capacity.

## Table 12-24 Status of all generation capacity (MW) in the PJM generation queue: 1997 through 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 | 32,728.5 | 6,666.5 | 676.5 | 151.3 | 1.9 | 0.0 | 371.5 | 1,639.0 | 156.4 | 0.0 | 440.1 | 1,655.4 | 1,343.0 | 723.0 | 0.0 | 60.9 | 8,455.7 | 55,286.6 |
| | Upgrade | 46.4 | 6,269.4 | 2,323.5 | 127.8 | 12.3 | 0.0 | 390.0 | 385.2 | 2,282.8 | 17.3 | 23.3 | 49.9 | 22.4 | 945.5 | 161.5 | 0.0 | 605.3 | 40.5 | 13,703.1 |
| Under Construction | New Generation | 4.5 | 5,311.0 | 205.0 | 0.0 | 0.0 | 0.0 | 0.0 | 22.7 | 0.0 | 1.3 | 0.0 | 0.0 | 782.3 | 0.0 | 0.0 | 0.0 | 0.0 | 1,879.5 | 8,206.3 |
| | Upgrade | 0.0 | 463.3 | 48.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 44.0 | 0.0 | 4.0 | 0.0 | 83.9 | 36.0 | 0.0 | 0.0 | 62.5 | 187.5 | 929.2 |
| Suspended | New Generation | 19.5 | 5,129.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 39.8 | 0.0 | 0.0 | 622.1 | 0.0 | 0.0 | 0.0 | 16.0 | 983.0 | 6,809.3 |
| | Upgrade | 23.0 | 675.1 | 230.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 27.6 | 0.0 | 0.0 | 0.0 | 0.0 | 16.3 | 972.0 |
| Withdrawn | New Generation | 1,982.3 | 208,752.2 | 2,755.8 | 1,721.0 | 1,244.2 | 5.5 | 500.0 | 1,986.9 | 8,161.0 | 400.1 | 63.9 | 88.6 | 33,470.2 | 33,511.6 | 27.0 | 0.0 | 1,034.9 | 73,474.6 | 369,179.8 |
| | Upgrade | 354.1 | 10,643.3 | 515.5 | 589.0 | 72.5 | 0.9 | 0.0 | 105.1 | 916.0 | 0.0 | 13.0 | 10.0 | 1,193.5 | 865.0 | 0.0 | 0.0 | 37.1 | 1,274.0 | 16,589.0 |
| Active | New Generation | 4,623.8 | 15,063.4 | 4,447.8 | 14.0 | 0.0 | 0.0 | 700.0 | 15.0 | 28.0 | 40.0 | 0.0 | 0.0 | 56,389.5 | 0.0 | 0.0 | 0.0 | 0.0 | 26,921.0 | 108,242.5 |
| | Upgrade | 1,591.4 | 2,909.0 | 1,534.7 | 13.0 | 0.0 | 3.0 | 0.0 | 51.0 | 95.5 | 0.0 | 0.0 | 0.8 | 3,308.9 | 60.0 | 64.0 | 0.0 | 40.0 | 1,327.8 | 10,999.1 |
| Total Projects | New Generation | 6,846.9 | 266,984.1 | 14,075.1 | 2,411.5 | 1,395.6 | 7.4 | 1,200.0 | 2,396.1 | 9,828.0 | 637.6 | 63.9 | 528.7 | 92,919.5 | 34,854.6 | 750.0 | 0.0 | 1,111.8 | 111,713.8 | 547,724.5 |
| | Upgrade | 2,014.9 | 20,960.1 | 4,651.7 | 729.8 | 84.8 | 3.9 | 390.0 | 541.3 | 3,338.3 | 17.3 | 40.3 | 60.7 | 4,636.3 | 1,906.5 | 225.5 | 0.0 | 744.9 | 2,846.1 | 43,192.4 |

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

## Table 12-25 Status of all generation queue projects as percent of total MW in project classification: 1997 through 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 | 3.2% | 12.3% | 47.4% | 28.1% | 10.8% | 26.2% | 0.0% | 15.5% | 16.7% | 24.5% | 0.0% | 83.2% | 1.8% | 3.9% | 96.4% | 0.0% | 5.5% | 7.6% | 10.1% |
| | Upgrade | 2.3% | 29.9% | 49.9% | 17.5% | 14.5% | 0.0% | 100.0% | 71.2% | 68.4% | 100.0% | 57.8% | 82.2% | 0.5% | 49.6% | 71.6% | 0.0% | 81.3% | 1.4% | 31.7% |
| Under Construction | New Generation | 0.1% | 2.0% | 1.5% | 0.0% | 0.0% | 0.0% | 0.0% | 0.9% | 0.0% | 0.2% | 0.0% | 0.0% | 0.8% | 0.0% | 0.0% | 0.0% | 0.0% | 1.7% | 1.5% |
| | Upgrade | 0.0% | 2.2% | 1.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 1.3% | 0.0% | 9.9% | 0.0% | 1.8% | 1.9% | 0.0% | 0.0% | 8.4% | 6.6% | 2.2% |
| Suspended | New Generation | 0.3% | 1.9% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 6.2% | 0.0% | 0.0% | 0.7% | 0.0% | 0.0% | 0.0% | 1.4% | 0.9% | 1.2% |
| | Upgrade | 1.1% | 3.2% | 4.9% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.6% | 0.0% | 0.0% | 0.0% | 0.0% | 0.6% | 2.3% |
| Withdrawn | New Generation | 29.0% | 78.2% | 19.6% | 71.4% | 89.2% | 73.8% | 41.7% | 82.9% | 83.0% | 62.8% | 100.0% | 16.8% | 36.0% | 96.1% | 3.6% | 0.0% | 93.1% | 65.8% | 67.4% |
| | Upgrade | 17.6% | 50.8% | 11.1% | 80.7% | 85.5% | 24.0% | 0.0% | 19.4% | 27.4% | 0.0% | 32.3% | 16.5% | 25.7% | 45.4% | 0.0% | 0.0% | 5.0% | 44.8% | 38.4% |
| Active | New Generation | 67.5% | 5.6% | 31.6% | 0.6% | 0.0% | 0.0% | 58.3% | 0.6% | 0.3% | 6.3% | 0.0% | 0.0% | 60.7% | 0.0% | 0.0% | 0.0% | 0.0% | 24.1% | 19.8% |
| | Upgrade | 79.0% | 13.9% | 33.0% | 1.8% | 0.0% | 76.0% | 0.0% | 9.4% | 2.9% | 0.0% | 0.0% | 1.3% | 71.4% | 3.1% | 28.4% | 0.0% | 5.4% | 46.7% | 25.5% |

Table 12-26 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 91.1 percent of all new projects entering the generation queue have been either combined cycle (21.5 percent), wind (21.5 percent) or solar projects (48.1 percent).

## Table 12-26 Queue project MW by unit type and queue entry year: 1997 through 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 | 161.6 | 368.0 | 0.0 | 0.0 | 56.5 | 3.3 | 9,078.0 | 190.0 | 0.0 | 50.5 | 18,525.6 | 43,700.6 |
| 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 | 11,066.1 | 41,773.7 |
| 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 | 3,678.8 | 64.0 | 0.0 | 0.0 | 173.5 | 9,848.4 | 23,942.5 |
| 2011 | 24.1 | 19,769.5 | 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 | 28,304.3 |
| 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 | 10,493.1 | 1,201.8 | 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 | 1,590.0 | 1,730.5 | 27.0 | 0.0 | 43.1 | 1,689.7 | 19,099.0 |
| 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 | 2,929.9 | 47.0 | 606.5 | 0.0 | 0.0 | 2,160.6 | 35,558.0 |
| 2016 | 111.1 | 18,802.5 | 1,392.0 | 0.0 | 0.0 | 3.4 | 0.0 | 12.5 | 50.3 | 23.5 | 0.0 | 38.9 | 11,770.3 | 80.0 | 77.0 | 0.0 | 0.0 | 3,467.5 | 35,828.9 |
| 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 | 13,874.6 | 14.0 | 17.0 | 0.0 | 0.0 | 5,432.0 | 25,727.4 |
| 2018 | 1,583.4 | 11,080.1 | 2,647.4 | 14.0 | 0.0 | 0.0 | 700.0 | 0.0 | 28.1 | 0.0 | 0.0 | 0.8 | 24,311.5 | 29.0 | 0.0 | 0.0 | 40.0 | 17,772.3 | 58,206.6 |
| 2019 | 5,737.4 | 3,132.5 | 1,608.1 | 13.0 | 0.0 | 3.0 | 500.0 | 99.0 | 0.0 | 0.0 | 0.0 | 0.0 | 36,155.4 | 11.0 | 0.0 | 0.0 | 0.0 | 11,873.8 | 59,133.2 |
| Total | 8,861.8 | 287,944.2 | 18,726.8 | 3,141.3 | 1,480.3 | 11.3 | 1,590.0 | 2,937.4 | 13,166.3 | 654.9 | 104.2 | 589.4 | 97,555.8 | 36,761.1 | 975.5 | 0.0 | 1,856.7 | 114,559.9 | 590,916.9 |

## 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 December 31, 2019, by zone. Of the 77 combined cycle projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 38 projects (49.4 percent) are located within AEP, ComEd and APS.

### Table 12-27 Status of all combined cycle queue projects by zo 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 | 4 | 0 | 5 | 2 | 4 | 10 | 6 | 0 | 61 |
| | Upgrade | 3 | 10 | 7 | 3 | 0 | 4 | 0 | 0 | 0 | 15 | 5 | 0 | 6 | 2 | 0 | 10 | 4 | 2 | 7 | 14 | 0 | 92 |
| Under Construction | New Generation | 0 | 3 | 1 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 |
| | Upgrade | 0 | 3 | 1 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 2 | 1 | 0 | 0 | 11 |
| Suspended | New Generation | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 5 |
| | Upgrade | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 5 |
| Withdrawn | New Generation | 22 | 19 | 43 | 13 | 8 | 14 | 0 | 1 | 2 | 17 | 17 | 3 | 26 | 25 | 0 | 43 | 40 | 33 | 40 | 54 | 2 | 422 |
| | Upgrade | 7 | 7 | 5 | 3 | 0 | 4 | 0 | 1 | 0 | 10 | 4 | 0 | 6 | 7 | 0 | 3 | 5 | 3 | 6 | 15 | 0 | 86 |
| Active | New Generation | 1 | 4 | 4 | 2 | 0 | 5 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 2 | 2 | 0 | 22 |
| | Upgrade | 1 | 4 | 7 | 1 | 0 | 3 | 0 | 0 | 0 | 2 | 0 | 0 | 1 | 2 | 0 | 1 | 2 | 0 | 3 | 1 | 0 | 28 |
| Total Projects | New Generation | 24 | 30 | 52 | 19 | 10 | 20 | 1 | 3 | 2 | 26 | 19 | 3 | 33 | 29 | 0 | 48 | 43 | 38 | 52 | 62 | 2 | 516 |
| | Upgrade | 11 | 24 | 21 | 9 | 0 | 11 | 0 | 1 | 0 | 27 | 10 | 0 | 14 | 11 | 0 | 16 | 11 | 9 | 17 | 30 | 0 | 222 |

Table 12-28 shows the status of all combined cycle projects by MW that entered PJM generation queues from 1997 through 2019, by zone. Of the 29,550.8 MW of combined cycle projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 15,373.3 MW (52.0 percent) are located within AEP, ComEd and APS.

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

| | | Project MW | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Project Status | Project Classification | AECO | AEP | APS | ATSI | BGE | ComEd | DAY | DEOK | DLCO | Dominion | DPL |
| 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 |
| | Upgrade | 229.0 | 328.0 | 790.0 | 306.0 | 0.0 | 633.6 | 0.0 | 0.0 | 0.0 | 963.0 | 102.0 |
| Under Construction | New Generation | 0.0 | 2,644.0 | 515.0 | 2,152.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | Upgrade | 0.0 | 191.0 | 20.0 | 38.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Suspended | New Generation | 0.0 | 0.0 | 1,575.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2,660.0 | 0.0 |
| | Upgrade | 0.0 | 0.0 | 45.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 451.0 |
| Withdrawn | New Generation | 7,967.4 | 12,509.5 | 20,122.1 | 8,641.0 | 3,122.1 | 10,142.0 | 0.0 | 134.5 | 665.0 | 11,261.0 | 5,436.4 |
| | Upgrade | 149.4 | 711.0 | 579.0 | 86.0 | 0.0 | 1,735.0 | 0.0 | 36.0 | 0.0 | 580.4 | 668.0 |
| Active | New Generation | 575.0 | 2,685.0 | 2,516.0 | 1,895.0 | 0.0 | 3,600.9 | 1,150.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | Upgrade | 7.6 | 551.0 | 918.7 | 550.0 | 0.0 | 111.7 | 0.0 | 0.0 | 0.0 | 90.0 | 0.0 |
| Total Projects | New Generation | 9,192.4 | 20,870.5 | 26,183.1 | 14,287.0 | 3,262.1 | 14,342.9 | 1,150.0 | 667.5 | 665.0 | 19,775.1 | 5,755.6 |
| | Upgrade | 386.0 | 1,781.0 | 2,352.7 | 980.0 | 0.0 | 2,480.3 | 0.0 | 36.0 | 0.0 | 1,633.4 | 1,221.0 |

| Project Status | Project Classification | EKPC | JCPL | Met-Ed | OVEC | PECO | PENELEC | Pepco | PPL | PSEG | RECO | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| In Service | New Generation | 0.0 | 1,665.8 | 2,557.0 | 0.0 | 2,665.0 | 1,900.0 | 1,560.0 | 5,750.0 | 2,448.5 | 0.0 | 32,728.5 |
| | Upgrade | 0.0 | 110.0 | 45.0 | 0.0 | 973.5 | 142.3 | 89.1 | 712.0 | 845.9 | 0.0 | 6,269.4 |
| Under Construction | New Generation | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 5,311.0 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 35.0 | 0.0 | 139.5 | 39.8 | 0.0 | 0.0 | 463.3 |
| Suspended | New Generation | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 894.0 | 0.0 | 0.0 | 0.0 | 5,129.0 |
| | Upgrade | 0.0 | 35.0 | 0.0 | 0.0 | 0.0 | 0.0 | 144.1 | 0.0 | 0.0 | 0.0 | 675.1 |
| Withdrawn | New Generation | 991.8 | 13,562.6 | 13,001.0 | 0.0 | 23,340.0 | 15,951.0 | 20,414.2 | 17,270.7 | 24,213.1 | 6.9 | 208,752.2 |
| | Upgrade | 0.0 | 273.0 | 1,742.0 | 0.0 | 240.0 | 1,040.6 | 85.0 | 500.0 | 2,217.9 | 0.0 | 10,643.3 |
| Active | New Generation | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 163.0 | 0.0 | 1,647.0 | 831.5 | 0.0 | 15,063.4 |
| | Upgrade | 0.0 | 105.0 | 113.9 | 0.0 | 67.0 | 85.0 | 0.0 | 258.0 | 51.1 | 0.0 | 2,909.0 |
| Total Projects | New Generation | 991.8 | 15,228.4 | 15,558.0 | 0.0 | 26,005.0 | 18,014.0 | 22,868.2 | 24,667.7 | 27,493.1 | 6.9 | 266,984.1 |
| | Upgrade | 0.0 | 523.0 | 1,900.9 | 0.0 | 1,315.5 | 1,267.9 | 457.7 | 1,509.8 | 3,114.9 | 0.0 | 20,960.1 |

## 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 1997 through 2019, by zone. Of the 62 combustion turbine natural gas projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 23 projects (37.1 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): 1997 through 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 | 3 | 7 | 0 | 3 | 1 | 0 | 2 | 4 | 2 | 4 | 9 | 0 | 49 |
| | Upgrade | 4 | 7 | 7 | 1 | 0 | 9 | 6 | 0 | 0 | 26 | 7 | 0 | 0 | 1 | 0 | 2 | 2 | 3 | 4 | 14 | 0 | 93 |
| 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 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Upgrade | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 |
| Withdrawn | New Generation | 1 | 5 | 0 | 0 | 1 | 1 | 1 | 0 | 0 | 2 | 0 | 1 | 0 | 0 | 0 | 1 | 5 | 0 | 1 | 5 | 0 | 24 |
| | Upgrade | 2 | 1 | 1 | 1 | 0 | 2 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 12 |
| Active | New Generation | 1 | 1 | 0 | 0 | 1 | 2 | 0 | 0 | 1 | 4 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 1 | 0 | 13 |
| | Upgrade | 0 | 2 | 3 | 6 | 0 | 13 | 3 | 0 | 1 | 2 | 0 | 0 | 3 | 4 | 0 | 1 | 6 | 0 | 0 | 0 | 0 | 44 |
| Total Projects | New Generation | 7 | 6 | 6 | 0 | 5 | 3 | 1 | 0 | 2 | 9 | 7 | 1 | 3 | 1 | 0 | 4 | 10 | 2 | 5 | 15 | 0 | 87 |
| | Upgrade | 6 | 10 | 12 | 8 | 0 | 25 | 9 | 0 | 1 | 31 | 7 | 0 | 5 | 6 | 0 | 3 | 9 | 3 | 4 | 14 | 0 | 153 |

Table 12-30 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation queues from, 1997 through 2019, by zone. Of the 6,465.5 MW of combustion turbine natural gas projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 1,918.7 MW (29.7 percent) are located within AEP, ComEd and APS.

### Table 12-30 Status of all combustion turbine - natural gas queue projects by zone (MW): 1997 through 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 | 1,081.0 | 1,491.0 | 0.0 | 522.1 | 10.0 | 0.0 | 559.0 | 361.9 | 5.0 | 150.9 | 925.9 | 0.0 | 6,666.5 |
| | 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 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | Upgrade | 0.0 | 0.0 | 30.0 | 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 | 230.0 |
| Withdrawn | New Generation | 7.5 | 989.5 | 0.0 | 0.0 | 9.0 | 10.0 | 104.0 | 0.0 | 0.0 | 75.5 | 0.0 | 73.0 | 0.0 | 0.0 | 0.0 | 0.5 | 326.8 | 0.0 | 19.9 | 1,140.1 | 0.0 | 2,755.8 |
| | Upgrade | 165.5 | 6.0 | 4.0 | 25.0 | 0.0 | 23.0 | 0.0 | 0.0 | 0.0 | 57.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 235.0 | 0.0 | 0.0 | 0.0 | 0.0 | 515.5 |
| Active | New Generation | 230.0 | 529.5 | 0.0 | 0.0 | 144.6 | 230.0 | 0.0 | 0.0 | 14.4 | 2,132.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 29.0 | 463.0 | 0.0 | 0.0 | 675.0 | 0.0 | 4,447.8 |
| | Upgrade | 0.0 | 38.0 | 82.0 | 116.0 | 0.0 | 961.2 | 127.5 | 0.0 | 15.0 | 38.0 | 0.0 | 0.0 | 21.0 | 13.5 | 0.0 | 0.0 | 122.5 | 0.0 | 0.0 | 0.0 | 0.0 | 1,534.7 |
| Total Projects | New Generation | 598.2 | 1,519.0 | 1,176.0 | 0.0 | 176.6 | 240.0 | 104.0 | 0.0 | 219.4 | 3,288.8 | 1,491.0 | 73.0 | 522.1 | 10.0 | 0.0 | 588.5 | 1,151.7 | 5.0 | 170.8 | 2,741.0 | 0.0 | 14,075.1 |
| | Upgrade | 209.2 | 234.0 | 303.7 | 181.0 | 0.0 | 1,289.2 | 187.5 | 0.0 | 15.0 | 982.7 | 86.0 | 0.0 | 221.0 | 47.6 | 0.0 | 13.0 | 382.5 | 32.0 | 252.3 | 215.0 | 0.0 | 4,651.7 |

## Wind Project Analysis

Table 12-31 shows the status of all wind generation projects by number of, 2019, by zone. Of the 91 wind projects to achieve in service status, 52 projects (57.1 percent) are located within AEP, ComEd and APS. Of the 122 wind projects currently active, suspended or under construction in the PJM generation queue, 84 projects (68.9 percent) are located within AEP, ComEd and APS.

### Table 12-31 Status of all wind generation queue projects by zone (number of projects): 1997 through 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 | 21 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 23 | 0 | 8 | 0 | 0 | 83 |
| | Upgrade | 0 | 0 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 0 | 0 | 0 | 0 | 8 |
| Under Construction | New Generation | 0 | 5 | 3 | 0 | 0 | 3 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 12 |
| | Upgrade | 0 | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 |
| Suspended | New Generation | 0 | 3 | 2 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 2 | 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 | 101 | 41 | 8 | 0 | 105 | 15 | 0 | 0 | 21 | 10 | 1 | 1 | 0 | 0 | 0 | 63 | 0 | 46 | 1 | 0 | 429 |
| | Upgrade | 2 | 1 | 6 | 0 | 0 | 7 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 0 | 2 | 0 | 0 | 27 |
| Active | New Generation | 7 | 22 | 7 | 3 | 0 | 25 | 0 | 0 | 0 | 7 | 4 | 0 | 6 | 0 | 0 | 0 | 1 | 0 | 2 | 0 | 0 | 84 |
| | Upgrade | 0 | 1 | 3 | 0 | 0 | 7 | 0 | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 14 |
| Total Projects | New Generation | 24 | 145 | 67 | 11 | 0 | 154 | 15 | 0 | 0 | 32 | 14 | 1 | 7 | 0 | 0 | 0 | 88 | 0 | 58 | 1 | 0 | 617 |
| | Upgrade | 2 | 2 | 11 | 0 | 0 | 18 | 0 | 0 | 0 | 3 | 1 | 0 | 1 | 0 | 0 | 0 | 12 | 0 | 2 | 0 | 0 | 52 |

Table 12-32 shows the status of all wind projects by MW that entered PJM generation queues from 1997 through 2019, by zone. Of the 8,496.2 MW of wind generation nameplate capacity to achieve the in service status, 6,866.2 MW (80.8 percent) of nameplate capacity is located within AEP, ComEd and APS. Of the 31,315.0 MW of wind generation nameplate capacity currently active, suspended or under construction in the PJM generation queue, 14,951.6 MW of generation nameplate capacity (47.7 percent) is located within AEP, ComEd and APS.

### Table 12-32 Status of all wind generation queue projects by zone (MW): 1997 through 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 | 3,103.5 | 0.0 | 0.0 | 0.0 | 310.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,065.0 | 0.0 | 226.5 | 0.0 | 0.0 | 8,455.7 |
| | Upgrade | 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 | 0.0 | 0.0 | 0.0 | 20.5 | 0.0 | 0.0 | 0.0 | 0.0 | 40.5 |
| Under Construction | New Generation | 0.0 | 855.9 | 310.6 | 0.0 | 0.0 | 701.0 | 0.0 | 0.0 | 0.0 | 12.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,879.5 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 187.5 | 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 | 187.5 |
| Suspended | New Generation | 0.0 | 422.0 | 219.1 | 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 | 165.3 | 0.0 | 0.0 | 983.0 |
| | 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 | 21,019.9 | 3,134.1 | 1,295.6 | 0.0 | 24,519.2 | 2,128.0 | 0.0 | 0.0 | 4,988.4 | 2,816.8 | 150.3 | 1,104.0 | 0.0 | 0.0 | 0.0 | 5,277.0 | 0.0 | 3,375.1 | 20.0 | 0.0 | 73,474.7 |
| | Upgrade | 5.0 | 200.0 | 100.0 | 0.0 | 0.0 | 605.7 | 0.0 | 0.0 | 0.0 | 114.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 243.4 | 0.0 | 6.0 | 0.0 | 0.0 | 1,274.0 |
| Active | New Generation | 3,939.6 | 4,439.1 | 539.0 | 816.1 | 0.0 | 6,641.0 | 0.0 | 0.0 | 0.0 | 5,340.6 | 671.8 | 0.0 | 4,159.2 | 0.0 | 0.0 | 0.0 | 109.9 | 0.0 | 264.8 | 0.0 | 0.0 | 26,921.0 |
| | Upgrade | 0.0 | 170.0 | 24.4 | 0.0 | 0.0 | 425.7 | 0.0 | 0.0 | 0.0 | 0.0 | 7.3 | 0.0 | 600.0 | 0.0 | 0.0 | 0.0 | 100.3 | 0.0 | 0.0 | 0.0 | 0.0 | 1,327.8 |
| Total Projects | New Generation | 7,593.5 | 29,475.6 | 5,206.8 | 2,111.7 | 0.0 | 34,964.6 | 2,128.0 | 0.0 | 0.0 | 10,728.1 | 3,488.6 | 150.3 | 5,263.2 | 0.0 | 0.0 | 0.0 | 6,551.9 | 0.0 | 4,031.7 | 20.0 | 0.0 | 111,713.8 |
| | Upgrade | 5.0 | 370.0 | 140.7 | 0.0 | 0.0 | 1,238.9 | 0.0 | 0.0 | 0.0 | 114.0 | 7.3 | 0.0 | 600.0 | 0.0 | 0.0 | 0.0 | 364.2 | 0.0 | 6.0 | 0.0 | 0.0 | 2,846.1 |

## Solar Project Analysis

Table 12-33 shows the status of all solar generation projects by number of projects that entered PJM generation queues from 1997 through 2019, by zone. Of the 160 solar projects to achieve in service status, 9 projects (5.6 percent) are located within AEP, ComEd and APS. Of the 840 solar projects currently active, suspended or under construction in the PJM generation queue, 261 projects (31.1 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 December 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 | 23 | 11 | 0 | 44 | 0 | 0 | 1 | 0 | 0 | 2 | 42 | 0 | 141 |
| | Upgrade | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 3 | 8 | 0 | 7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 19 |
| Under Construction | New Generation | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 1 | 0 | 5 | 2 | 0 | 3 | 0 | 0 | 0 | 1 | 1 | 0 | 7 | 0 | 22 |
| | Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 |
| Suspended | New Generation | 0 | 4 | 10 | 0 | 0 | 0 | 1 | 0 | 0 | 3 | 0 | 0 | 3 | 2 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 24 |
| | Upgrade | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 |
| Withdrawn | New Generation | 176 | 94 | 71 | 14 | 13 | 34 | 17 | 13 | 1 | 178 | 125 | 8 | 185 | 17 | 1 | 7 | 21 | 17 | 35 | 95 | 0 | 1,122 |
| | Upgrade | 2 | 3 | 1 | 0 | 0 | 3 | 0 | 0 | 0 | 14 | 1 | 0 | 8 | 0 | 0 | 0 | 0 | 1 | 0 | 3 | 1 | 37 |
| Active | New Generation | 18 | 135 | 57 | 26 | 2 | 33 | 21 | 6 | 3 | 190 | 38 | 25 | 12 | 22 | 0 | 2 | 61 | 13 | 26 | 3 | 1 | 694 |
| | Upgrade | 2 | 11 | 4 | 3 | 0 | 5 | 5 | 2 | 1 | 36 | 6 | 3 | 4 | 2 | 0 | 0 | 2 | 0 | 5 | 4 | 1 | 96 |
| Total Projects | New Generation | 201 | 237 | 144 | 40 | 16 | 68 | 40 | 20 | 4 | 399 | 176 | 33 | 247 | 41 | 1 | 10 | 83 | 31 | 63 | 148 | 1 | 2,003 |
| | Upgrade | 5 | 14 | 5 | 3 | 0 | 8 | 5 | 3 | 1 | 54 | 15 | 3 | 20 | 3 | 0 | 0 | 2 | 1 | 5 | 7 | 2 | 156 |

Table 12-34 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997 through December 31, 2019, by zone. Of the 1,677.8 MW of solar generation nameplate capacity to achieve in service status, 76.7 MW (4.6 percent) of nameplate capacity is located within AEP, ComEd and APS. Of the 61,214.3 MW of solar generation capacity currently active, suspended or under construction in the PJM generation queue, 24,500.8 MW of generation nameplate capacity (40.0 percent) is located within AEP, ComEd and APS.

Table 12-34 Status of all solar generation queue projects by zone (MW): January 1997 through December 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 | 830.8 | 130.4 | 0.0 | 311.6 | 0.0 | 0.0 | 3.3 | 0.0 | 0.0 | 15.0 | 226.7 | 0.0 | 1,655.4 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 8.1 | 0.0 | 0.0 | 14.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 22.4 |
| Under Construction | New Generation | 0.0 | 0.0 | 14.3 | 0.0 | 0.0 | 0.0 | 0.0 | 125.0 | 0.0 | 382.4 | 170.0 | 0.0 | 51.9 | 0.0 | 0.0 | 0.0 | 13.5 | 2.5 | 0.0 | 22.7 | 0.0 | 782.3 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 75.0 | 0.0 | 8.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 83.9 |
| Suspended | New Generation | 0.0 | 40.0 | 219.1 | 0.0 | 0.0 | 0.0 | 20.0 | 0.0 | 0.0 | 291.0 | 0.0 | 0.0 | 8.0 | 38.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 6.0 | 0.0 | 622.1 |
| | Upgrade | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 7.6 | 20.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 27.6 |
| Withdrawn | New Generation | 1,835.3 | 7,351.7 | 1,911.2 | 628.2 | 57.3 | 2,331.8 | 1,023.9 | 379.4 | 20.0 | 11,300.4 | 1,648.4 | 899.9 | 1,460.0 | 586.0 | 78.0 | 69.4 | 526.7 | 188.7 | 618.6 | 555.3 | 0.0 | 33,470.2 |
| | Upgrade | 10.0 | 126.0 | 0.0 | 0.0 | 0.0 | 40.0 | 0.0 | 0.0 | 0.0 | 968.8 | 0.0 | 0.0 | 23.8 | 0.0 | 0.0 | 0.0 | 0.0 | 3.6 | 0.0 | 1.3 | 20.0 | 1,193.5 |
| Active | New Generation | 559.2 | 16,976.1 | 2,058.1 | 2,442.8 | 40.0 | 4,004.5 | 2,385.7 | 349.9 | 45.9 | 17,095.6 | 1,470.0 | 2,545.0 | 230.0 | 957.3 | 0.0 | 29.8 | 3,967.7 | 188.2 | 971.3 | 32.5 | 40.0 | 56,389.5 |
| | Upgrade | 160.0 | 653.8 | 134.9 | 78.0 | 0.0 | 400.0 | 158.5 | 10.0 | 8.3 | 1,183.6 | 75.0 | 140.0 | 0.0 | 40.0 | 0.0 | 0.0 | 180.0 | 0.0 | 60.0 | 6.8 | 20.0 | 3,308.9 |
| Total Projects | New Generation | 2,451.7 | 24,382.6 | 4,255.7 | 3,071.0 | 98.4 | 6,345.3 | 3,432.1 | 854.3 | 65.9 | 29,900.2 | 3,418.8 | 3,444.9 | 2,061.4 | 1,581.3 | 78.0 | 102.5 | 4,507.9 | 379.4 | 1,604.9 | 843.2 | 40.0 | 92,919.5 |
| | Upgrade | 170.0 | 779.8 | 134.9 | 78.0 | 0.0 | 440.0 | 158.5 | 85.0 | 8.3 | 2,169.4 | 75.0 | 140.0 | 45.7 | 60.0 | 0.0 | 0.0 | 180.0 | 3.6 | 60.0 | 8.1 | 40.0 | 4,636.3 |

## 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."[34] 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 nonincumbent 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 December 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 590,916.9 MW that have entered the queue during the time period of January 1, 1997, through December 31, 2019, 66,695.8 MW (11.3 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 37,010.5 MW that entered the queue during the time period of January 1, 1997, through December 31, 2019, 14,287.3 MW (38.6 percent) have been submitted by PSEG or one of their affiliated companies.

34 See OATT § 1 (Transmission Owner).

## Table 12-35 Relationship between project developer and transmission owner for all interconnection queue projects MW by unit type: December 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 | 678.0 | 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 | 5,092.7 |
| | | Unrelated | 587 | 1,746.6 | 21,973.5 | 1,753.0 | 7.5 | 127.3 | 0.0 | 0.0 | 453.6 | 0.0 | 12.0 | 0.0 | 75.4 | 25,019.7 | 10,379.0 | 0.0 | 0.0 | 492.0 | 29,845.6 | 91,885.1 |
| 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 | 72 | 129.9 | 1,150.0 | 253.5 | 0.0 | 1.9 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 10.0 | 3,569.1 | 0.0 | 0.0 | 0.0 | 0.0 | 2,128.0 | 7,242.4 |
| 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 | 27 | 20.0 | 665.0 | 234.4 | 40.0 | 19.2 | 0.0 | 0.0 | 106.0 | 1,879.0 | 0.0 | 0.0 | 0.0 | 74.2 | 2,810.0 | 0.0 | 0.0 | 0.0 | 0.0 | 5,847.8 |
| Dominion | Dominion | Related | 110 | 0.0 | 12,364.0 | 2,045.7 | 100.0 | 0.0 | 0.0 | 340.0 | 0.0 | 1,944.0 | 0.0 | 0.0 | 60.0 | 1,574.4 | 301.0 | 0.0 | 0.0 | 4.0 | 2,786.0 | 21,519.1 |
| | | Unrelated | 568 | 1,348.1 | 9,044.5 | 2,225.8 | 0.5 | 227.3 | 0.0 | 0.0 | 35.0 | 0.0 | 0.0 | 10.0 | 119.4 | 30,495.2 | 20.0 | 0.0 | 0.0 | 316.3 | 8,056.1 | 51,898.3 |
| Duke | DEOK | Related | 9 | 23.8 | 36.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 106.4 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 166.2 |
| | | Unrelated | 32 | 140.4 | 667.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 112.0 | 0.0 | 0.0 | 0.0 | 4.8 | 832.9 | 120.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,877.6 |
| 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 | 40 | 20.3 | 170.0 | 73.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 3,584.9 | 0.0 | 0.0 | 0.0 | 0.0 | 150.3 | 3,998.5 |
| 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 | 327 | 941.0 | 8,848.4 | 807.4 | 388.0 | 20.7 | 2.8 | 0.0 | 0.0 | 0.0 | 2.0 | 5.0 | 10.3 | 2,613.5 | 15.0 | 5.5 | 0.0 | 10.0 | 7,598.5 | 21,268.0 |
| | 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 | 61 | 240.6 | 3,012.1 | 166.6 | 18.0 | 133.0 | 0.0 | 0.0 | 0.4 | 3,280.0 | 1.3 | 0.0 | 0.0 | 78.4 | 0.0 | 2.5 | 0.0 | 25.0 | 0.0 | 6,957.9 |
| | 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 | 383 | 887.3 | 16,823.2 | 1,529.2 | 42.0 | 65.2 | 0.0 | 0.0 | 22.7 | 0.0 | 35.0 | 0.0 | 67.7 | 6,776.3 | 1,926.0 | 91.0 | 0.0 | 90.0 | 36,203.5 | 64,559.0 |
| | 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 | 299 | 186.5 | 5,611.6 | 1,226.0 | 600.9 | 42.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 84.6 | 3,486.4 | 653.0 | 15.0 | 0.0 | 65.0 | 3,495.9 | 15,467.5 |
| | 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 | 83 | 25.3 | 20,355.5 | 596.5 | 2.0 | 15.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 17.0 | 3.7 | 102.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 21,117.5 |
| | 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 | 95 | 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 | 383.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 25,480.4 |
| 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 | 409 | 590.9 | 27,082.8 | 1,479.7 | 0.0 | 84.4 | 0.0 | 0.0 | 623.3 | 0.0 | 140.0 | 53.8 | 25.4 | 4,390.6 | 4,092.0 | 0.0 | 0.0 | 184.4 | 5,347.5 | 44,094.8 |
| | 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 | 109 | 76.4 | 13,589.0 | 181.0 | 10.5 | 166.4 | 0.0 | 0.0 | 0.0 | 0.0 | 59.7 | 0.0 | 6.9 | 3,149.0 | 0.0 | 16.5 | 0.0 | 0.0 | 2,111.7 | 19,367.1 |
| | 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 | 395 | 1,042.0 | 15,751.4 | 743.1 | 0.0 | 4.8 | 0.6 | 0.0 | 1.6 | 0.0 | 0.6 | 0.0 | 12.8 | 2,095.1 | 0.0 | 0.0 | 0.0 | 30.0 | 5,863.2 | 25,545.2 |
| | 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 | 130 | 63.0 | 17,458.9 | 57.6 | 1,204.4 | 52.1 | 0.0 | 0.0 | 0.0 | 93.0 | 0.0 | 8.0 | 23.2 | 1,641.3 | 0.0 | 0.0 | 0.0 | 84.0 | 0.0 | 20,685.5 |
| | 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 | 319 | 269.4 | 18,747.9 | 1,529.2 | 0.0 | 214.4 | 3.0 | 16.0 | 46.3 | 0.0 | 341.8 | 8.0 | 14.8 | 4,687.9 | 561.0 | 590.0 | 0.0 | 525.0 | 6,916.1 | 34,470.5 |
| 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 | 1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 78.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 78.0 |
| 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 | 271 | 579.8 | 23,916.5 | 423.1 | 8.0 | 234.5 | 0.0 | 1,200.0 | 142.6 | 388.0 | 19.9 | 2.4 | 44.7 | 1,645.1 | 6,896.6 | 0.0 | 0.0 | 31.0 | 4,037.7 | 39,569.9 |
| 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 | 184.1 | 24.0 | 44.0 | 0.0 | 0.0 | 0.0 | 14,287.3 |
| | | Unrelated | 222 | 414.5 | 18,771.9 | 1,137.9 | 600.0 | 62.5 | 4.9 | 0.0 | 1,000.0 | 0.0 | 10.6 | 0.0 | 13.7 | 667.2 | 0.0 | 20.0 | 0.0 | 0.0 | 20.0 | 22,723.2 |
| 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 | 5 | 0.0 | 6.9 | 0.0 | 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 | 86.9 |
| Total | | Related | 403 | 119.8 | 40,971.9 | 4,272.8 | 189.5 | 0.0 | 0.0 | 374.0 | 394.0 | 5,886.3 | 0.0 | 0.0 | 68.5 | 2,105.5 | 9,288.5 | 235.0 | 0.0 | 4.0 | 2,786.0 | 66,695.8 |
| | | Unrelated | 4435 | 8,742.0 | 246,972.3 | 14,454.0 | 2,951.8 | 1,480.3 | 11.3 | 1,216.0 | 2,543.4 | 7,280.0 | 654.9 | 104.2 | 520.9 | 95,450.2 | 27,472.6 | 740.5 | 0.0 | 1,852.7 | 111,773.9 | 524,221.1 |

## 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 December 31, 2019, by transmission owner and project status. Of the 44,772.2 combined cycle project MW that have achieved in service or under construction status during this time period, 9,254.0 MW (20.7 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 December 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: December 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 | 678.0 | 0.0 | 0.0 | 0.0 | 678.0 |
| | | Unrelated | 3,236.0 | 2,682.0 | 2,835.0 | 0.0 | 13,220.5 | 21,973.5 |
| AES | DAY | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 1,150.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1,150.0 |
| DLCO | DLCO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 665.0 | 665.0 |
| Dominion | Dominion | Related | 90.0 | 4,773.0 | 0.0 | 0.0 | 7,501.0 | 12,364.0 |
| | | Unrelated | 0.0 | 2,044.1 | 0.0 | 2,660.0 | 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 | 582.6 | 879.0 | 0.0 | 0.0 | 7,386.8 | 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 | 3,712.6 | 1,233.6 | 0.0 | 0.0 | 11,877.0 | 16,823.2 |
| | 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 | 3,434.7 | 1,720.0 | 535.0 | 1,620.0 | 19,773.1 | 27,082.8 |
| | ATSI | Related | 0.0 | 0.0 | 0.0 | 0.0 | 1,678.0 | 1,678.0 |
| | | Unrelated | 2,445.0 | 1,905.0 | 2,190.0 | 0.0 | 7,049.0 | 13,589.0 |
| | JCPL | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 105.0 | 1,775.8 | 0.0 | 35.0 | 13,835.6 | 15,751.4 |
| | Met-Ed | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 113.9 | 2,602.0 | 0.0 | 0.0 | 14,743.0 | 17,458.9 |
| | PENELEC | Related | 0.0 | 0.0 | 0.0 | 0.0 | 534.0 | 534.0 |
| | | Unrelated | 248.0 | 2,042.3 | 0.0 | 0.0 | 16,457.6 | 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 | 1,905.0 | 5,862.0 | 39.8 | 0.0 | 16,109.7 | 23,916.5 |
| PSEG | PSEG | Related | 51.1 | 2,488.0 | 0.0 | 0.0 | 9,297.0 | 11,836.1 |
| | | Unrelated | 831.5 | 806.4 | 0.0 | 0.0 | 17,134.0 | 18,771.9 |
| 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 | 6.9 | 6.9 |
| Total | | Related | 141.1 | 9,254.0 | 0.0 | 0.0 | 31,576.8 | 40,971.9 |
| | | Unrelated | 17,831.3 | 29,743.9 | 5,774.3 | 5,804.1 | 187,818.6 | 246,972.3 |

## 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 December 31, 2019, by transmission owner and project status. Of the 9,243.0 CT – natural gas project MW that have achieved in service or under construction status during this time period, 2,107.0 (22.8 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 2,956.0 MW that entered the queue during the time period of January 1, 1997, through December 31, 2019, 1,818.1 MW (61.5 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: December 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 | 567.5 | 190.0 | 0.0 | 0.0 | 995.5 | 1,753.0 |
| AES | DAY | Related | 0.0 | 38.0 | 0.0 | 0.0 | 0.0 | 38.0 |
| | | Unrelated | 127.5 | 22.0 | 0.0 | 0.0 | 104.0 | 253.5 |
| DLCO | DLCO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 29.4 | 0.0 | 205.0 | 0.0 | 0.0 | 234.4 |
| Dominion | Dominion | Related | 1,202.7 | 786.0 | 0.0 | 0.0 | 57.0 | 2,045.7 |
| | | Unrelated | 967.6 | 1,182.7 | 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 | 0.0 | 0.0 | 0.0 | 0.0 | 73.0 | 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 | 144.6 | 13.0 | 0.0 | 0.0 | 9.0 | 166.6 |
| | ComEd | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 1,191.2 | 257.0 | 48.0 | 0.0 | 33.0 | 1,529.2 |
| | 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 | 82.0 | 1,363.7 | 0.0 | 30.0 | 4.0 | 1,479.7 |
| | ATSI | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 116.0 | 40.0 | 0.0 | 0.0 | 25.0 | 181.0 |
| | JCPL | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 21.0 | 522.1 | 0.0 | 200.0 | 0.0 | 743.1 |
| | Met-Ed | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 13.5 | 44.1 | 0.0 | 0.0 | 0.0 | 57.6 |
| | PENELEC | Related | 0.0 | 5.0 | 0.0 | 0.0 | 0.0 | 5.0 |
| | | Unrelated | 585.5 | 381.9 | 0.0 | 0.0 | 561.8 | 1,529.2 |
| 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 | 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 | 675.0 | 228.9 | 0.0 | 0.0 | 234.0 | 1,137.9 |
| 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 | 1,202.7 | 2,107.0 | 0.0 | 0.0 | 963.1 | 4,272.8 |
| | | Unrelated | 4,779.8 | 6,883.0 | 253.0 | 230.0 | 2,308.2 | 14,454.0 |

## 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 December 31, 2019, by transmission owner and project status. Of the 10,563.2 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 10,842.1 MW that entered the queue during the time period of January 1, 1997, through December 31, 2019, 2,786.0 MW (25.7 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: December 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 | 4,609.1 | 2,738.7 | 855.9 | 422.0 | 21,219.9 | 29,845.6 |
| AES | DAY | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 2,128.0 | 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 | 2,640.0 | 0.0 | 12.0 | 0.0 | 134.0 | 2,786.0 |
| | | Unrelated | 2,700.6 | 310.5 | 0.0 | 76.6 | 4,968.4 | 8,056.1 |
| 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 | 3,939.6 | 7.5 | 0.0 | 0.0 | 3,651.4 | 7,598.5 |
| | 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 | 7,066.7 | 3,123.5 | 888.5 | 0.0 | 25,124.8 | 36,203.5 |
| | DPL | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 679.1 | 0.0 | 0.0 | 0.0 | 2,816.8 | 3,495.9 |
| | 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 | 563.4 | 1,004.0 | 310.6 | 235.4 | 3,234.1 | 5,347.5 |
| | 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 | 4,759.2 | 0.0 | 0.0 | 0.0 | 1,104.0 | 5,863.2 |
| | 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 | 210.2 | 1,085.5 | 0.0 | 100.0 | 5,520.3 | 6,916.1 |
| 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 | 264.8 | 226.5 | 0.0 | 165.3 | 3,381.1 | 4,037.7 |
| 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 | 2,640.0 | 0.0 | 12.0 | 0.0 | 134.0 | 2,786.0 |
| | | Unrelated | 25,608.8 | 8,496.2 | 2,055.0 | 999.3 | 74,614.7 | 111,773.9 |

## Solar Project Developer and Transmission Owner Relationships

Table 12-39 shows the relationship between the project developer and transmission owner for all solar project MW that have entered the PJM generation queue from January 1, 1997 through December 31, 2019, by transmission owner and project status. Of the 2,543.9 solar project MW that have achieved in service or under construction status during this time period, 816.9 MW (32.1 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 solar projects in their own service territory. Of the 851.3 MW that entered the queue during the time period of January 1, 1997, through December 31, 2019, 184.1 MW (21.6 percent) have been submitted by PSEG 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: December 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 | 17,561.9 | 0.0 | 0.0 | 30.0 | 7,427.7 | 25,019.7 |
| AES | DAY | Related | 0.0 | 0.0 | 0.0 | 0.0 | 21.5 | 21.5 |
| | | Unrelated | 2,544.2 | 2.5 | 0.0 | 20.0 | 1,002.4 | 3,569.1 |
| DLCO | DLCO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 54.2 | 0.0 | 0.0 | 0.0 | 20.0 | 74.2 |
| Dominion | Dominion | Related | 696.1 | 429.1 | 217.3 | 0.0 | 231.9 | 1,574.4 |
| | | Unrelated | 17,583.1 | 409.8 | 174.0 | 291.0 | 12,037.3 | 30,495.2 |
| Duke | DEOK | Related | 100.0 | 0.0 | 0.0 | 0.0 | 6.4 | 106.4 |
| | | Unrelated | 259.9 | 0.0 | 200.0 | 0.0 | 373.0 | 832.9 |
| EKPC | EKPC | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 2,685.0 | 0.0 | 0.0 | 0.0 | 899.9 | 3,584.9 |
| Exelon | AECO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 8.3 | 8.3 |
| | | Unrelated | 719.2 | 57.3 | 0.0 | 0.0 | 1,837.0 | 2,613.5 |
| | BGE | Related | 0.0 | 0.0 | 0.0 | 0.0 | 20.0 | 20.0 |
| | | Unrelated | 40.0 | 1.1 | 0.0 | 0.0 | 37.3 | 78.4 |
| | ComEd | Related | 0.0 | 9.0 | 0.0 | 0.0 | 0.0 | 9.0 |
| | | Unrelated | 4,404.5 | 0.0 | 0.0 | 0.0 | 2,371.8 | 6,776.3 |
| | DPL | Related | 0.0 | 7.4 | 0.0 | 0.0 | 0.0 | 7.4 |
| | | Unrelated | 1,545.0 | 123.0 | 170.0 | 0.0 | 1,648.4 | 3,486.4 |
| | PECO | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 29.8 | 3.3 | 0.0 | 0.0 | 69.4 | 102.5 |
| | Pepco | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 188.2 | 0.0 | 2.5 | 0.0 | 192.3 | 383.0 |
| FirstEnergy | APS | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 2,193.0 | 53.0 | 14.3 | 219.1 | 1,911.2 | 4,390.6 |
| | ATSI | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 2,520.8 | 0.0 | 0.0 | 0.0 | 628.2 | 3,149.0 |
| | JCPL | Related | 0.0 | 0.0 | 0.0 | 0.0 | 12.0 | 12.0 |
| | | Unrelated | 230.0 | 325.9 | 51.9 | 15.6 | 1,471.8 | 2,095.1 |
| | Met-Ed | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 997.3 | 0.0 | 0.0 | 58.0 | 586.0 | 1,641.3 |
| | PENELEC | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 4,147.7 | 0.0 | 13.5 | 0.0 | 526.7 | 4,687.9 |
| OVEC | OVEC | Related | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | | Unrelated | 0.0 | 0.0 | 0.0 | 0.0 | 78.0 | 78.0 |
| PPL | PPL | Related | 19.8 | 0.0 | 0.0 | 0.0 | 0.0 | 19.8 |
| | | Unrelated | 1,011.5 | 15.0 | 0.0 | 0.0 | 618.6 | 1,645.1 |
| PSEG | PSEG | Related | 3.8 | 134.3 | 5.1 | 0.0 | 40.9 | 184.1 |
| | | Unrelated | 35.5 | 92.4 | 17.6 | 6.0 | 515.7 | 667.2 |
| 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 | 20.0 | 80.0 |
| Total | | Related | 887.7 | 594.5 | 222.4 | 10.0 | 391.0 | 2,105.5 |
| | | Unrelated | 58,810.7 | 1,083.3 | 643.8 | 639.7 | 34,272.7 | 95,450.2 |

# Regional Transmission Expansion Plan (RTEP)[35]

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.

## 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.[36] 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.[37]

PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. The 2013 window was open from August 12, 2013, through September 26, 2013. This window accepted proposals to address historical congestion on 25 identified flowgates. PJM received 17 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. The 2014/2015 long term window was open from November 1, 2014, through February 28, 2015. This window accepted proposals to address historical congestion on 12 identified flowgates. PJM received 93 proposals from 19 entities. Thirteen projects were approved by the PJM Board.

The second market efficiency cycle was performed during the 2016/2017 RTEP long term window. The 2016/2017 long term window was open from November 1, 2016, through February 28, 2017. This window

35 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. 46 (Aug. 28, 2019).

36 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>.

37 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>.

accepted proposals to address historical congestion on four identified flowgates. PJM received 96 proposals from 20 entities. Four projects were approved by the PJM Board.

PJM also held an addendum 2016/2017 long term window. This 2016/2017 1A long term window was open from September 14, 2017, through September 28, 2017. This window accepted proposals to address historical congestion on one identified flowgate. PJM received three proposals from two entities. One project was approved by the PJM Board.

The fourth market efficiency cycle was performed for the 2018/2019 RTEP long term window. The 2018/2019 long term window was open from November 2, 2018, through March 15, 2019. This window accepted proposals to address historical congestion on one internal and three interregional flowgates. PJM received 33 proposals from 10 entities. One project was approved by the PJM Board to address the historical congestion on the internal flowgate, and one project was approved by the PJM Board to address the historical congestion on one of the interregional flowgates.[38]

## 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. PJM measures benefits as 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 but does not weight increases and decreases in benefits equally. 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, 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.

The definition of the energy benefit analysis depends on whether the project is regional or subregional. For a regional project, the energy benefit for each modeled year is equal to 50 percent of the change in system wide total system energy production costs with and without the project plus 50 percent of the change in zonal load payments with and without the project, including only those zones where the project reduced the load payments. For subregional projects, the calculation of benefits for each modeled year ignores any impact on system wide energy production costs and is instead based only the change in zonal load energy payments with and without the project, but including only those zones where the project reduced the load energy payments.

In both the regional and subregional analysis, changes in zonal load energy payments are netted against changes in the estimated value of any Auction Revenue Rights (ARR) that sink in that zone for purposes of determining whether a zone benefits from a proposed RTEP project. 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 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 (RPM) Benefit analysis is conducted using the RPM solution software, with and without the proposed RTEP project, using a set of estimated capacity offers.

38 No proposals effectively resolved the congestion on two of the three identified interregional market efficiency flowgates. One proposal received provisional approval by the PJM Board, pending approval by the MISO Board.

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 payments with and without the project plus 50 percent of the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments. For subregional projects, the reliability pricing model benefits for each modeled year ignores any impact on system wide total capacity payments and is equal to the change in zonal capacity payments with and without the project, including only those zones where the project reduced the 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 load costs that an RTEP project may create in some zones when calculating the energy and capacity 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. If the approach is retained, a more appropriate measure of the benefits of a competing transmission project would be either the change in total system wide load costs, after the allocation of congestion, with and without the project or the change in total system production costs with and without the project. The current rules regarding cost allocation for regional project do not result in the beneficiary paying all of the costs of the project. The current rules do not account for the risk associated with the fact that the benefits of projects are uncertain and highly sensitive to the modeling assumptions used.

The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. The MMU recommends that the market efficiency process be eliminated.

## PJM MISO Interregional Market Efficiency Process (IMEP)

PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion. To qualify as an IMEP project, the project must be evaluated in a joint study process, qualify as an economic transmission enhancement in both PJM and MISO transmission expansion models and meet specific IMEP cost benefit criteria.[39] The allocation of costs to each RTO for IMEPs will be in proportion to the benefits received.

PJM and MISO conducted a two year interregional market efficiency project study in 2018/2019 and included the investigation of forward looking congestion on three market to market flowgates. Proposals were received during the 2018/2019 long term window, which was open from November 2, 2018, through March 15, 2019. PJM and MISO received 10 proposals from seven entities. As a result of this analysis, the RTOs recommended one IMEP project.[40] The approved project has an in service cost of $24.7 million and a PJM benefit/cost ratio of

39 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

40 Analysis showed that no projects met the B/C criteria on two of the identified flowgates.

2.63. The PJM board approved the recommended project in December 2019. As of December 31, 2019, the project was still being considered for recommendation to the MISO Board.

## PJM MISO Targeted Market Efficiency Process (TMEP)

PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects. The TMEP process operates on a 12 month study schedule. To qualify as a TMEP project, the project must have an estimated in service date by the third summer peak season from the year the project was approved, have an estimated cost of less than $20 million and meet specific TMEP cost benefit criteria.[41] The allocation of costs to each RTO for TMEPs will be in proportion to the benefits received.[42]

On November 2, 2017, PJM submitted a compliance filing including additional revisions to the MISO-PJM JOA to include stakeholder feedback in the TMEP project selection process.[43]

The first Targeted Market Efficiency Process (TMEP) analysis occurred in 2017 and included the investigation of historical congestion on an initial set of 50 market to market flowgates. The causes of congestion on these flowgates were analyzed. If the historical congestion was a result of outages, or if the congestion was expected to be mitigated by planned upgrades already included in the PJM RTEP or MISO MTEP, then the flowgate was eliminated from consideration in the TMEP process. As a result of this analysis, potential short term upgrades were identified for 13 of the initial 50 flowgates. PJM and MISO conducted a market efficiency and power flow analysis to determine the potential to eliminate the identified congestion on the 13 flowgates. As a result of this analysis, the RTOs recommended five TMEP projects. The five projects address $59.0 million in historical congestion, with a TMEP benefit of $99.6 million. The projects have a total cost of $20.0 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.[44]

The second Targeted Market Efficiency Process analysis occurred in 2018 and included the investigation of historical congestion on an initial set of 61 market to market flowgates. The causes of congestion on these flowgates were analyzed. If the historical congestion was a result of outages, or if the congestion was expected to be mitigated by planned upgrades already included in the PJM RTEP or MISO MTEP, then the flowgate was eliminated from consideration in the TMEP process. As a result of this analysis, potential short term upgrades were identified for 20 of the initial 61 flowgates. PJM and MISO conducted a market efficiency and power flow analysis to determine the potential to eliminate the identified congestion on the 20 flowgates. As a result of this analysis, the RTOs recommended two TMEP projects. The two projects address $25.0 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.[45]

With only one additional year of historical information, and the fact that many of the same constraints were evaluated in the 2018 TMEP process, PJM and MISO did not conduct a TMEP study in 2019.

## Supplemental Transmission Projects

Supplemental projects are asserted to be "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."[46] 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.

41 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

42 See *PJM Interconnection, L.L.C*, Docket No. ER17-729-000 (December 30, 2016).

43 See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000, et al. (November 2, 2017).

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

45 See PJM. "*MISO PJM IPSAC*," (January 18, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20190118/20190118-ipsac-presentation.ashx>.

46 See PJM. Planning. "Transmission Construction Status," (Accessed on December 31, 2019) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

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 baseline and 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 baseline and supplemental projects by expected in service year: 1998 through 2020

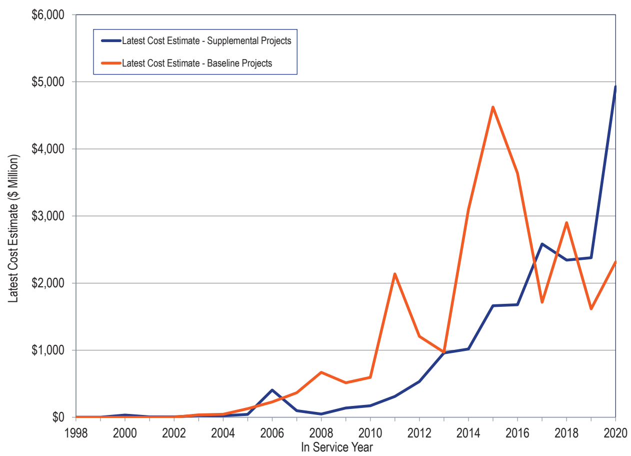


Table 12-40 shows the number of supplemental projects by expected in service year for each transmission zone. The average number of supplemental projects in each expected in service year increased by 620.0 percent, from 20 for years 1998 through 2007 (pre Order 890) to 144 for years 2008 through 2019 (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 | 1 | 2 | 0 | 39 |
| 2010 | 0 | 6 | 7 | 0 | 3 | 4 | 0 | 0 | 6 | 3 | 0 | 0 | 1 | 2 | 0 | 2 | 0 | 0 | 3 | 5 | 0 | 42 |
| 2011 | 0 | 8 | 8 | 0 | 0 | 2 | 0 | 0 | 5 | 2 | 0 | 0 | 1 | 0 | 0 | 4 | 0 | 0 | 6 | 4 | 0 | 40 |
| 2012 | 0 | 5 | 6 | 4 | 1 | 2 | 0 | 7 | 3 | 16 | 1 | 0 | 2 | 0 | 0 | 1 | 0 | 0 | 5 | 11 | 0 | 64 |
| 2013 | 5 | 21 | 4 | 5 | 0 | 11 | 0 | 6 | 5 | 13 | 1 | 0 | 1 | 1 | 0 | 1 | 0 | 1 | 14 | 19 | 0 | 108 |
| 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 | 6 | 15 | 4 | 17 | 0 | 26 | 0 | 6 | 2 | 13 | 4 | 2 | 0 | 1 | 0 | 3 | 2 | 3 | 11 | 30 | 0 | 145 |
| 2017 | 8 | 104 | 3 | 26 | 1 | 23 | 0 | 3 | 8 | 31 | 11 | 5 | 0 | 3 | 0 | 0 | 3 | 1 | 21 | 43 | 0 | 294 |
| 2018 | 10 | 134 | 4 | 13 | 1 | 20 | 0 | 15 | 4 | 23 | 6 | 4 | 0 | 0 | 0 | 2 | 0 | 1 | 20 | 26 | 0 | 283 |
| 2019 | 3 | 139 | 4 | 33 | 6 | 17 | 3 | 20 | 1 | 35 | 9 | 7 | 16 | 56 | 0 | 1 | 18 | 1 | 12 | 24 | 0 | 405 |
| 2020 | 3 | 210 | 2 | 33 | 4 | 6 | 5 | 22 | 2 | 25 | 2 | 5 | 0 | 28 | 0 | 0 | 78 | 0 | 21 | 29 | 0 | 475 |
| 2021 | 4 | 126 | 0 | 28 | 1 | 5 | 5 | 4 | 1 | 17 | 3 | 6 | 1 | 41 | 0 | 4 | 56 | 0 | 35 | 23 | 1 | 361 |
| 2022 | 5 | 97 | 0 | 12 | 2 | 0 | 3 | 2 | 0 | 7 | 7 | 1 | 0 | 9 | 0 | 4 | 28 | 3 | 23 | 20 | 0 | 223 |
| 2023 | 7 | 7 | 0 | 5 | 2 | 1 | 5 | 1 | 3 | 5 | 0 | 0 | 0 | 13 | 0 | 2 | 7 | 0 | 16 | 24 | 0 | 98 |
| 2024 | 4 | 1 | 1 | 1 | 2 | 0 | 0 | 1 | 0 | 0 | 2 | 1 | 2 | 1 | 0 | 0 | 0 | 1 | 12 | 1 | 0 | 30 |
| 2025 | 3 | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 0 | 0 | 14 |
| 2026 | 4 | 0 | 0 | 0 | 8 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 7 | 0 | 0 | 20 |
| 2027 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 11 | 0 | 0 | 12 |
| 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 | 0 | 0 | 0 | 0 |
| 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 | 0 | 0 | 0 | 0 |
| Total | 91 | 925 | 96 | 194 | 43 | 207 | 21 | 100 | 58 | 237 | 155 | 37 | 32 | 156 | 0 | 32 | 202 | 15 | 246 | 313 | 1 | 3,161 |

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 1,684.0 percent, from $64.5 million for years 1998 through 2007 (pre Order 890) to $1,151.8 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 | $0.77 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.77 |
| 2000 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $32.94 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $32.94 |
| 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 | $8.77 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $9.60 | $0.00 | $0.00 | $0.00 | $0.00 | $25.79 |
| 2004 | $4.45 | $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 | $14.66 | $10.11 | $0.00 | $0.00 | $2.57 | $0.00 | $0.00 | $0.00 | $0.02 | $10.98 | $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 | $0.93 | $0.00 | $0.00 | $48.92 | $0.00 | $0.00 | $0.00 | $0.00 | $11.62 | $0.00 | $6.00 | $0.00 | $0.00 | $0.00 | $1.50 | $0.00 | $4.63 | $18.80 | $0.00 | $406.13 |
| 2007 | $0.56 | $2.06 | $9.85 | $0.00 | $37.61 | $4.65 | $0.00 | $0.00 | $31.75 | $0.00 | $9.72 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.34 | $2.28 | $0.00 | $98.82 |
| 2008 | $2.36 | $0.00 | $12.03 | $0.00 | $0.45 | $7.61 | $0.00 | $0.00 | $7.00 | $14.01 | $2.27 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $1.59 | $0.00 | $0.00 | $47.32 |
| 2009 | $0.77 | $0.90 | $12.22 | $0.00 | $5.00 | $21.11 | $0.00 | $0.00 | $19.60 | $2.12 | $7.35 | $0.00 | $0.00 | $0.00 | $0.00 | $48.10 | $2.73 | $0.00 | $0.16 | $17.60 | $0.00 | $137.66 |
| 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 | $1.86 | $17.72 | $0.00 | $172.19 |
| 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 | $11.87 | $34.60 | $0.00 | $311.22 |
| 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 | $19.66 | $223.01 | $0.00 | $532.54 |
| 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 | $76.70 | $503.72 | $0.00 | $959.51 |
| 2014 | $8.03 | $387.00 | $5.97 | $58.70 | $21.20 | $60.37 | $0.00 | $2.43 | $14.90 | $88.61 | $5.95 | $0.38 | $5.60 | $0.00 | $0.00 | $13.30 | $1.30 | $0.00 | $33.47 | $309.71 | $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 | $74.54 | $83.63 | $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 | $1,676.94 |
| 2017 | $66.28 | $646.04 | $8.60 | $164.45 | $0.09 | $145.97 | $0.00 | $64.31 | $3.62 | $104.25 | $92.29 | $2.21 | $0.00 | $14.70 | $0.00 | $0.00 | $8.30 | $12.00 | $261.74 | $988.92 | $0.00 | $2,583.77 |
| 2018 | $66.55 | $779.57 | $14.80 | $42.12 | $4.08 | $80.94 | $0.00 | $69.80 | $4.98 | $168.29 | $68.94 | $10.87 | $0.00 | $0.00 | $0.00 | $47.60 | $0.00 | $156.00 | $197.34 | $631.25 | $0.00 | $2,343.13 |
| 2019 | $64.30 | $870.96 | $10.64 | $234.50 | $76.58 | $99.69 | $0.68 | $86.37 | $0.30 | $77.34 | $39.65 | $27.62 | $7.80 | $103.88 | $0.00 | $2.00 | $79.20 | $70.00 | $272.20 | $254.49 | $0.00 | $2,378.20 |
| 2020 | $21.20 | $1,640.80 | $0.28 | $124.09 | $59.80 | $64.80 | $15.28 | $142.10 | $23.10 | $73.38 | $27.40 | $24.67 | $0.00 | $99.90 | $0.00 | $0.00 | $243.96 | $0.00 | $249.65 | $2,118.24 | $0.00 | $4,928.65 |
| 2021 | $37.08 | $1,415.90 | $0.00 | $260.55 | $1.94 | $68.00 | $29.90 | $14.74 | $26.20 | $149.78 | $18.61 | $27.51 | $16.00 | $146.80 | $0.00 | $27.00 | $72.90 | $0.00 | $413.45 | $833.30 | $17.00 | $3,576.66 |
| 2022 | $117.76 | $718.76 | $0.00 | $259.80 | $249.30 | $0.00 | $10.25 | $21.30 | $0.00 | $241.93 | $107.60 | $13.00 | $0.00 | $35.26 | $0.00 | $0.00 | $43.00 | $527.50 | $438.80 | $1,011.27 | $0.00 | $3,795.53 |
| 2023 | $90.64 | $191.30 | $0.00 | $106.20 | $82.60 | $1.00 | $32.85 | $14.20 | $135.40 | $53.30 | $0.00 | $0.00 | $0.00 | $90.50 | $0.00 | $89.00 | $342.50 | $0.00 | $208.31 | $563.00 | $0.00 | $2,000.80 |
| 2024 | $40.24 | $8.50 | $3.60 | $170.00 | $0.00 | $0.00 | $0.00 | $14.80 | $0.00 | $0.00 | $29.72 | $15.80 | $30.50 | $6.00 | $0.00 | $0.00 | $0.00 | $0.50 | $266.33 | $39.00 | $0.00 | $624.99 |
| 2025 | $28.89 | $0.00 | $0.00 | $0.00 | $148.22 | $0.00 | $0.00 | $0.00 | $0.00 | $1.40 | $11.20 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $158.20 | $0.00 | $0.00 | $347.91 |
| 2026 | $64.00 | $0.00 | $0.00 | $0.00 | $339.11 | $67.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $170.05 | $0.00 | $0.00 | $640.16 |
| 2027 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $4.70 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $0.00 | $233.78 | $0.00 | $0.00 | $238.48 |
| 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 | $0.00 | $0.00 | $0.00 | $0.00 |
| 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 | $0.00 | $0.00 | $0.00 | $0.00 |
| Total | $710.04 | $7,560.12 | $148.87 | $1,659.04 | $1,049.08 | $1,431.83 | $88.96 | $495.29 | $443.08 | $1,420.06 | $554.90 | $123.87 | $74.05 | $508.09 | $0.00 | $527.90 | $805.39 | $818.70 | $3,129.06 | $9,055.00 | $17.00 | $30,620.33 |

The MMU recommends, to increase the role of competition, that the exemption of supplemental 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.[47] Some Transmission Owners include end of life transmission projects in their Transmission Owner Form 715 Planning Criteria. Form 715 is the annual transmission planning and evaluation report that all utilities that operate a transmission facility rated at or above 100 kV are required to file with the Commission. The purpose of Form 715 is "to provide information adequate to inform potential transmission customers, State regulatory authorities and the public of potential transmission capacity and known constraints, to support the Commission's expanded responsibilities under §§ 211, 212 and 213(a) of the Federal Power Act (as amended by the Energy Policy Act), and to assist in rate or other regulatory proceedings."[48] Form 715 requires utilities to "provide a narrative evaluation or assessment of the performance of its transmission system in future time periods based on the application of its reliability criteria. It must provide a clear understanding of existing and

47 The useful life of a transmission investment typically exceeds its depreciable life.

48 See FERC. "*Form No. 715 – Annual Transmission Planning and Evaluation Report*," at <https://www.ferc.gov/docs-filing/forms/form-715/instructions.asp#general_information>.

likely future transmission constraints, their sources, how it identified these constraints, and a description of any plans to mitigate the constraints."[49]

Projects submitted through the Form 715 planning criteria were exempt from the competitive planning process.[50] On August 30, 2019, the Commission issued an Order on Remand, which rejected the 2015 PJM Transmission Owner Tariff Revisions that "allocate 100 percent of costs for projects that are included in the PJM Regional Transmission Expansion Plan (RTEP) solely to address individual transmission owner Form No. 715 local planning criteria to the transmission zone of the transmission owner whose Form No. 715 local planning criteria underlie each project."[51] The Order directed PJM to regionally allocate cost responsibility to Transmission Owner Form 715 Planning Criteria projects.[52] Additionally, On August 30, 2019, the Commission issued an Order Instituting Section 206 Proceeding that removed the proposal window exemption for Form No. 715 Planning Criteria.[53]

The Commission stated that "the transmission planning reforms that the Commission adopted in Order No. 890 were intended to address concerns regarding undue discrimination in grid expansion."[54] The Commission has further clarified that even if certain end of life supplemental projects increase transmission capacity they are exempt from the competitive planning process. The Commission stated that "we find that this type of incidental increase in transmission capacity that is a function of advancements in technology of the replaced equipment, and is not reasonably severable from the asset management project or activity, would not render the asset management project or activity in question a transmission expansion that is subject to the transmission planning requirements of Order No. 890."[55] The Commission did not address end of life projects that are not incidental. In PJM's October 7, 2019, compliance filing to the August 30, 2019 Order on Remand, PJM sought additional clarification on the treatment of asset management activities that are included in some Transmission Owner's Form No. 715 Planning Criteria.[56]

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 included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects.

## Competitive Planning Process Exclusions

There are several project types that are currently exempt from the competitive planning process. These project 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 defined to be infeasible and such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[57] On October 17, 2019, the Commission issued an Order Instituting Section 206 Proceedings to determine if RTOs have implemented the exemption in a manner consistent with the Commission's directives under Order 1000.[58]
- **Below 200kV:** Due to the lower voltage level of the identified violation(s), the driver(s) for this project are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[59]
- **FERC 715 (Transmission Owner (TO) Criteria):** Such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[60] Effective August 30, 2019, FERC 715 Criteria are no longer exempt from the competitive planning process.[61]
- **Substation Equipment:** Due to identification of the limiting element(s) as substation equipment, such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[62]

49 See FERC. "*Form No. 715 – Annual Transmission Planning and Evaluation Report*," at <https://www.ferc.gov/docs-filing/forms/form-715/instructions.asp#general_information>.
50 See PJM. Operating Agreement Schedule 6 § 1.5.8(o).
51 168 FERC ¶ 61,133 at P 1 (2019).
52 *Id.* at PP 29–31.
53 168 FERC ¶ 61,132 at P 13 (2019)..
54 164 FERC ¶ 61,160 at P 31 (2018).
55 *Id.* at P 33.
56 See PJM Interconnection, L.L.C. (October 7, 2019) (Docket Nos. EL19-61 and ER20-45).
57 See PJM Operating Agreement Schedule 6 § 1.5.8(m).
58 169 FERC ¶ 61,054 (October 17, 2019).
59 See PJM Operating Agreement Schedule 6 § 1.5.8(n).
60 See PJM Operating Agreement Schedule 6 § 1.5.8(o).
61 168 FERC ¶ 61,133 (August 30, 2019).
62 See PJM Operating Agreement Schedule 6 § 1.5.8(p).

While the PJM Operating Agreement defines who will be the Designated Entity for projects that are excluded from the competitive planning process, neither the PJM Operating Agreement nor the various commission orders on transmission competition prohibit PJM from permitting competition to provide financing for such projects. The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. In addition, the criteria for and need for all exclusions from the competitive process should be reviewed. There does not appear to be any market reason to exclude transmission projects from competition for any of these exclusion categories.

## 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.

## 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, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[63]

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.

In 2019, the PJM Board approved a net change of - $296.3 million in transmission upgrades. As of December 31, 2019, the PJM Board had approved $37.6 billion in transmission system enhancements since 1999. On February 12, 2019, the PJM Board of Managers authorized an additional $271.9 million in transmission upgrades and additions. On July 29, 2019, the PJM Board of Managers authorized an additional $327.8 million in transmission upgrades and additions. On September 30, 2019, the PJM Board of Managers authorized an additional $246.1 million in transmission upgrades and additions. On December 3, 2019, the PJM Board of Managers authorized a net change of -$1.14 billion in transmission upgrades and additions. This net decrease in transmission upgrades and additions was the result of the cancellation of previously approved network projects totaling $1.45 billion that were no longer needed as a result of withdrawn generation interconnection requests.

## Qualifying Transmission Upgrades (QTU)

A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions.

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, 2019, no QTUs have cleared a BRA.

## 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

63 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

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 included: 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 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 Line Ratings

Transmission line ratings, and more broadly transmission facility ratings, are the metric for the ability of transmission lines to transmit power from one point to another. Transmission line ratings have significant and frequently underappreciated impacts on competitive wholesale power markets like PJM. These include direct impacts on energy and capacity prices, the frequency and level of congestion in the Day-Ahead and Real-Time Energy Market, day-ahead nodal price differences and the associated value of FTRs, locational price differences in the capacity market, the need to invest in additional transmission capacity, the need to invest in additional generation capacity, the location of new power plants, and the interconnection costs for new power plants. The impact of transmission facility ratings on markets is a function both of the line ratings directly and the use of those ratings by the RTO/ISO.

Congestion payments by load result when lower cost generation is not available to meet all the load in an area as a result of limits on the transmission system. When higher cost local generation is needed to meet part of the local load because of transmission limits, 100 percent of the local load pays the higher price while only the local generation receives the higher price. The difference between what the load pays and generators receive is congestion. Since 2008, congestion costs in PJM have ranged from $0.5 billion to $2.05 billion per year. Congestion costs were significantly higher during extreme winter weather conditions such as January 2014, when the congestion costs in PJM were $825.1 million for one month.[66]

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing. Transmission penalty factors were fully implemented in PJM pricing effective February 1, 2019.

Transmission line ratings can result in short term, significant increases in prices as a result of the application of transmission penalty factors. For example, violation of a transmission constraint, meaning that the flow exceeds the line limit, could result in a $2,000 per MWh price. As the power flows approach their rated limits, PJM dispatchers may reduce the limits.[67] Violation of

64 153 FERC ¶ 61,245 at P 35 (2015).
65 See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).

66 See the *2018 State of the Market Report for PJM*, Volume 2, Section 11: Congestion and Marginal Losses.
67 See "Transmission Constraint Control Logic and Penalty Factors," presented at May 10, 2018 meeting of the Markets Implementation Committee Special Session Transmission Constraint Penalty Factors at p14. <https://www.pjm.com/-/media/committees-groups/committees/mic/20180510-special/20180510-item-03-transmission-constraint-penalty-factor-education.ashx>.

these reduced line ratings results in penalty factors setting prices. In 2019, there were 152,675 transmission constraint intervals in the real-time market with a non-zero shadow price. For nearly five percent of these transmission constraints, the line limit was violated, meaning the flow exceeded the facility limit and prices were set by transmission penalty factors. In 2019, the average shadow price of transmission constraints when the line limit was violated was nearly 15 times higher than when transmission constraint was binding at its limit.[68]

Capacity market prices separate locally when transmission capability into Locational Deliverable Areas (LDA) is not adequate to meet the LDA capacity requirement with the lowest cost capacity. The available transmission capability into LDAs is defined as the Capacity Emergency Transfer Limit (CETL). Higher cost LDAs are the equivalent in the capacity market of congestion in the energy market. Load in the higher cost LDAs pay more for capacity than those in lower cost LDAs. For example, the clearing price for the BGE LDA in the 2021/2022 Base Residual Auction was $200.30 per MW-day. The clearing price for the EMAAC LDA was $165.73 per MW-day.[69]

Transmission line ratings for a given transmission facility vary by the duration of the power flow, by ambient temperatures, by wind speed and by other conditions. Transmission lines can operate with higher loads for shorter periods of time. This is significant when a contingency is expected to last for only a short period. The transmission line rating can mean the difference between substantial congestion costs and no congestion costs. The transmission line rating can mean the difference between a transmission penalty factor and no penalty factor.

In PJM, transmission owners use a range of ratings by duration.[70] PJM requires transmission owners to provide thermal ratings under normal operating conditions, long term emergency operating conditions, short term emergency operating conditions and the extreme load dump conditions. But there is no requirement that the ratings differ for these operating conditions. PJM typically uses normal line ratings for precontingency (base case) constraints and long term emergency line ratings (four hours) for contingency constraints. PJM requires transmission owners to provide temperature based line ratings separately for night and day times. The temperature ranges from 32 degree Fahrenheit or below to 95 degree Fahrenheit or above in nine degree increments. But there is no requirement that the ratings differ for these operating condition temperatures. In PJM, transmission owners are responsible for developing their own methods to compute line ratings subject to a range of NERC guidelines and requirements. PJM does not review or verify the accuracy of transmission owners' methods to compute line ratings. In PJM, transmission owners have substantial discretion in the approach to line ratings. [71]

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. PJM real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings. For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real time conditions and to help ensure that real-time prices are based on actual current line ratings. The ongoing analysis of dynamic line ratings is a promising area that should be pursued.

The MMU recommends that all PJM transmission owners use the same methods to define line ratings, subject to NERC standards and guidelines, subject to review by NERC and approval by FERC. The same facilities should have the same basic ratings under the same operating conditions regardless of the transmission owner. Transmission owner discretion should be minimized or eliminated. The line rating methods should be based on the basic engineering facts of the transmission system components and reflect the impact of actual operating conditions on the ratings of transmission facilities, including ambient temperatures and wind speed when

68 See the *2019 State of the Market Report for PJM*, Volume 2, Section 3: Energy Market.

69 See the "Analysis of the 2021/2022 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24 2018).

70 See "PJM Manual 3: Transmission Operations," Rev. 56 (Dec. 5, 2019) § 2.1.1, at p 28.

71 PJM presentation to the Planning Committee (PC) (May 3, 2018) "Transmission Owner Ratings Development and Reporting in PJM" ("There are no requirements for PJM to approve or verify a TO's ratings or do any kind of consistency check.") at 24.

relevant.[72] The line rating methods should be public and fully transparent.

The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice.[73] All line rating changes and the detailed reasons for those changes should be public and fully transparent.

## 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.[74] 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.[75] The specific timeline is shown in Table 12-43.[76]

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 2018/2019 planning period and the first seven months of the 2019/2020 planning period, regardless of when they were initially submitted.[77] The outage data for the day-ahead market are for outages scheduled to occur from January 2015 through December 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.[78] Table 12-42 shows that 74.7 percent of requested outages were planned for less than or equal to five days and 9.9 percent of requested outages were planned for greater than 30 days in the first seven months of 2019/2020 planning period. Table 12-42 also shows that 77.0 percent of the requested outages were planned for less than or equal to five days and 7.8 percent of requested outages were planned for greater than 30 days in the 2018/2019 planning period.

**Table 12-42 Transmission facility outage request summary by planned duration: June 2018 through December 2019**

| | 2018/2019 (12 months) | | 2019/2020 (7 months) | |
|---|---|---|---|---|
| Planned Duration (Days) | Outage Requests | Percent of Total | Outage Requests | Percent of Total |
| <=5 | 17,002 | 77.0% | 9,022 | 74.7% |
| >5 & <=30 | 3,376 | 15.3% | 1,861 | 15.4% |
| >30 | 1,714 | 7.8% | 1,192 | 9.9% |
| Total | 22,092 | 100.0% | 12,075 | 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.[79]

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.[80]

72 See "Transmission Owner Ratings Development and Reporting in PJM," presented at May 3, 2018 meeting of the Planning Committee. <https://www.pjm.com/-/media/committees-groups/committees/pc/20180503/20180503-item-13-to-ratings-process-and-reporting.ashx>.

73 *See* the *2018 State of the Market Report for PJM*, Volume 2, Section 2: Recommendations.

74 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. 56 (Dec. 5, 2019).

75 See PJM. "Manual 3: Transmission Operations," Rev. 56 (Dec. 5, 2019).

76 See PJ., "Manual 3: Transmission Operations," Rev. 56 (Dec. 5, 2019).

77 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.

78 *Id.* at 70.

79 See PJM. "Manual 3: Transmission Operations," Rev. 56 (Dec. 5, 2019).

80 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 seven months of the 2019/2020 planning period, 48.1 percent of outage requests received were late. In the 2018/2019 planning period, 47.3 percent of outage requests received were late.

### Table 12-44 Transmission facility outage request summary by received status: June 2018 through December 2019

| | 2018/2019 (12 months) | | | | 2019/2020 (7 months) | | | |
|---|---|---|---|---|---|---|---|---|
| Planned Duration (Days) | On Time | Late | Total | Percent Late | On Time | Late | Total | Percent Late |
| <=5 | 9,305 | 7,697 | 17,002 | 45.3% | 4,777 | 4,245 | 9,022 | 47.1% |
| >5 & <=30 | 1,633 | 1,743 | 3,376 | 51.6% | 998 | 863 | 1,861 | 46.4% |
| >30 | 701 | 1,013 | 1,714 | 59.1% | 489 | 703 | 1,192 | 59.0% |
| Total | 11,639 | 10,453 | 22,092 | 47.3% | 6,264 | 5,811 | 12,075 | 48.1% |

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.[81]

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.[82] Table 12-45 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the first seven months of 2019/2020 planning period, 13.5 percent were for emergency outages. Of all outage requests scheduled to occur in the 2018/2019 planning period, 12.5 percent were for emergency outages.

### Table 12-45 Transmission facility outage request summary by emergency: June 2018 through December 2019

| | 2018/2019 (12 months) | | | | 2019/2020 (7 months) | | | |
|---|---|---|---|---|---|---|---|---|
| Planned Duration (Days) | Emergency | Non Emergency | Total | Percent Emergency | Emergency | Non Emergency | Total | Percent Emergency |
| <=5 | 2,024 | 14,978 | 17,002 | 11.9% | 1,201 | 7,821 | 9,022 | 13.3% |
| >5 & <=30 | 469 | 2,907 | 3,376 | 13.9% | 253 | 1,608 | 1,861 | 13.6% |
| >30 | 263 | 1,451 | 1,714 | 15.3% | 181 | 1,011 | 1,192 | 15.2% |
| Total | 2,756 | 19,336 | 22,092 | 12.5% | 1,635 | 10,440 | 12,075 | 13.5% |

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."[83]

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

81 See PJM. "Manual 3: Transmission Operations," Rev. 56 (Dec. 5, 2019). 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).

82 PJM. "Manual 3: Transmission Operations," Rev. 56 (Dec. 5, 2019).

83 PJM added this definition to Manual 38 in February 2017. PJM. "Manual 38: Operations Planning," Rev. 13 (Jan. 23, 2020).

contributing to the congestion, PJM can request that the generation owner defer the outage. If no solutions are available, PJM may require the transmission owner to reschedule or cancel the outage.

Table 12-46 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the first seven months of the 2019/2020 planning period, 7.7 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 2.5 percent (23 out of 924) were denied by PJM in the first seven months of the 2019/2020 planning period and 20.1 percent (186 out of 924) were cancelled (Table 12-48). Of all outage requests submitted to occur in the 2018/2019 planning period, 7.1 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 4.2 percent (66 out of 1,567) were denied by PJM in the 2018/2019 planning period and 21.9 percent (343 out of 1,567) were cancelled (Table 12-48).

### Table 12-46 Transmission facility outage request summary by congestion: June 2018 through December 2019

| | 2018/2019 (12 months) | | | | 2019/2020 (7 months) | | | |
|---|---|---|---|---|---|---|---|---|
| Planned Duration (Days) | Congestion Expected | No Congestion Expected | Total | Percent Congestion Expected | Congestion Expected | No Congestion Expected | Total | Percent Congestion Expected |
| <=5 | 1,138 | 15,864 | 17,002 | 6.7% | 641 | 8,381 | 9,022 | 7.1% |
| >5 & <=30 | 270 | 3,106 | 3,376 | 8.0% | 167 | 1,694 | 1,861 | 9.0% |
| >30 | 159 | 1,555 | 1,714 | 9.3% | 116 | 1,076 | 1,192 | 9.7% |
| Total | 1,567 | 20,525 | 22,092 | 7.1% | 924 | 11,151 | 12,075 | 7.7% |

Table 12-47 shows the outage requests summary by received status, congestion status and emergency status. In the first seven months of the 2019/2020 planning period, 34.7 percent of requests were submitted late and were nonemergency while 1.5 percent of requests (176 out of 12,075) were late, nonemergency, and expected to cause congestion. In the 2018/2019 planning period, 34.9 percent of request were submitted late and were nonemergency while 1.1 percent of requests (250 out of 22,092) were late, nonemergency, and expected to cause congestion.

### Table 12-47 Transmission facility outage request summary by received status, emergency and congestion: June 2018 through December 2019

| | | 2018/2019 (12 months) | | | | 2019/2020 (7 months) | | | |
|---|---|---|---|---|---|---|---|---|---|
| Received Status | | Congestion Expected | No Congestion Expected | Total | Percent of Total | Congestion Expected | No Congestion Expected | Total | Percent of Total |
| Late | Emergency | 72 | 2,663 | 2,735 | 12.4% | 45 | 1,571 | 1,616 | 13.4% |
| | Non Emergency | 250 | 7,468 | 7,718 | 34.9% | 176 | 4,019 | 4,195 | 34.7% |
| On Time | Emergency | 3 | 18 | 21 | 0.1% | 3 | 16 | 19 | 0.2% |
| | Non Emergency | 1,242 | 10,376 | 11,618 | 52.6% | 700 | 5,545 | 6,245 | 51.7% |
| Total | | 1,567 | 20,525 | 22,092 | 100.0% | 924 | 11,151 | 12,075 | 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.[84] 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, 2.5 percent (23 out of 924) were denied by PJM in the first seven months of the 2019/2020 planning period, 66.3 percent were complete and 20.1 percent (186 out of 924) were cancelled. Of all the outage requests that were expected to cause congestion, 4.2 percent (66 out of 1,567) were denied by PJM in the 2018/2019 planning period, 68.0 percent were complete and 21.9 percent (343 out of 1,567) were cancelled.

84 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2019).

Table 12-48 Transmission facility outage requests that might cause congestion status summary: June 2018 through December 2019

| | | 2018/2019 (12 months) | | | | | | 2019/2020 (7 months) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Received Status | | Cancelled | Complete | In Process | Denied | Congestion Expected | Percent Complete | Cancelled | Complete | In Process | Denied | Congestion Expected | Percent Complete |
| Late | Emergency | 7 | 64 | 0 | 0 | 72 | 88.9% | 3 | 40 | 1 | 0 | 45 | 88.9% |
| | Non Emergency | 47 | 170 | 10 | 20 | 250 | 68.0% | 28 | 137 | 5 | 4 | 176 | 77.8% |
| On Time | Emergency | 0 | 3 | 0 | 0 | 3 | 100.0% | 1 | 2 | 0 | 0 | 3 | 66.7% |
| | Non Emergency | 289 | 828 | 72 | 46 | 1,242 | 66.7% | 154 | 434 | 85 | 19 | 700 | 62.0% |
| Total | | 343 | 1,065 | 82 | 66 | 1,567 | 68.0% | 186 | 613 | 91 | 23 | 924 | 66.3% |

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[85] 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 2018/2019 planning period, 250 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 2018/2019 planning period and the first seven months of the 2019/2020 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 seven months of the 2019/2020 planning period, 31.0 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 11.6 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2018/2019 planning period, 33.1 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 12.4 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

Table 12-49 Rescheduled and cancelled transmission outage request summary: June 2018 through December 2019

| | 2018/2019 (12 months) | | | | | 2019/2020 (7 months) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 17,002 | 4,063 | 23.9% | 2,449 | 14.4% | 9,022 | 2,073 | 23.0% | 1,245 | 13.8% |
| >5 & <=30 | 3,376 | 2,097 | 62.1% | 221 | 6.5% | 1,861 | 1,020 | 54.8% | 110 | 5.9% |
| >30 | 1,714 | 1,144 | 66.7% | 59 | 3.4% | 1,192 | 646 | 54.2% | 43 | 3.6% |
| Total | 22,092 | 7,304 | 33.1% | 2,729 | 12.4% | 12,075 | 3,739 | 31.0% | 1,398 | 11.6% |

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.[86] 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

85 PJM Operating Agreement Schedule 1 § 1.9.2.
86 PJM. "Manual 3: Transmission Operations," Rev. 56 (Dec. 5, 2019).

to the revised month in which the outage will occur.[87] This rescheduling rule is much less strict than the rule that applies to the first submission of outage requests with similar duration. When first submitted, the outage request with a duration exceeding five days needs to be submitted before the first of the month six months prior to the month in which the outage was expected to occur. The 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 8,384 transmission equipment planned outages in the first seven months of the 2019/2020 planning period, of which 1,160 were longer than 30 days, and of which 88 or 1.0 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 2018 through December 2019

| | | 2018/2019 (12 months) | | 2019/2020 (7 months) | |
|---|---|---|---|---|---|
| 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 | 1,476 | 11.3% | 1,072 | 12.8% |
| | Yes | 246 | 1.9% | 88 | 1.0% |
| <= 30 | | 11,380 | 86.9% | 7,224 | 86.2% |
| Total | | 13,102 | 100.0% | 8,384 | 100.0% |

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 seven months of the 2019/2020 planning period, within effective duration greater than a month and shorter than two months, there were 24 outages with a combined duration longer than 30 days.

### Table 12-51 Equipment outages: June 2018 through December 2019

| | 2018/2019 (12 months) | | 2019/2020 (7 months) | |
|---|---|---|---|---|
| Effective Duration of Outage | Count of Equipment with Planned Outages | Percent of Total | Count of Equipment with Planned Outages | Percent of Total |
| <=31 | 3 | 1.2% | 2 | 2.3% |
| >31 & <=62 | 26 | 10.6% | 24 | 27.3% |
| >62 & <=93 | 22 | 8.9% | 13 | 14.8% |
| >93 | 195 | 79.3% | 49 | 55.7% |
| Total | 246 | 100.0% | 88 | 100.0% |

87 *Id.*

## 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 weeks as an initial list. Then PJM may exercise significant discretion in selecting outages to be modeled in the final model. PJM posts the final FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[88]

In the first seven months of the 2019/2020 planning period, 180 outage requests were included in the annual FTR market outage list and 11,895 outage requests were not included.[89] In the 2018/2019 planning period, 239 outage requests were included in the annual FTR market outage list and 21,853 outage requests were not included. Table 12-52, Table 12-53, Table 12-54 and Table 12-55 show the summary information on the modeled outage requests and Table 12-56 and Table 12-57 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-52 shows that 6.1 percent of the outage requests modeled in the Annual FTR Market for the first seven months of the 2019/2020 planning period had a planned duration of less than two weeks and that 18.9 percent of the outage requests (34 out of 180) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 9.2 percent of the outage requests modeled in the Annual FTR Market for the 2018/2019 planning period had a planned duration of less than two weeks and that 16.7 percent of the outage requests (40 out of 239) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

**Table 12-52 Annual FTR market modeled transmission facility outage requests by received status: June 2018 through December 2019**

| | 2018/2019 (12 months) | | | | 2019/2020 (7 months) | | | |
|---|---|---|---|---|---|---|---|---|
| Planned Duration | On Time | Late | Total | Percent of Total | On Time | Late | Total | Percent of Total |
| <2 weeks | 19 | 3 | 22 | 9.2% | 8 | 3 | 11 | 6.1% |
| >=2 weeks & <2 months | 65 | 9 | 74 | 31.0% | 51 | 5 | 56 | 31.1% |
| >=2 months | 115 | 28 | 143 | 59.8% | 87 | 26 | 113 | 62.8% |
| Total | 199 | 40 | 239 | 100.0% | 146 | 34 | 180 | 100.0% |

Table 12-53 shows the annual FTR market modeled outage requests summary by emergency status and received status. Two of the annual FTR market modeled outages expected to occur in the first seven months of the 2019/2020 planning period were emergency outages. One of the modeled outages expected to occur in the 2018/2019 planning period was an emergency outage.

88 PJM Financial Transmission Rights, "Annual ARR Allocation and FTR Auction Transmission Outage Modeling," <https://www.pjm.com/-/media/markets-ops/ftr/annual-ftr-auction/2018-2019/2018-2019-annual-outage-modeling.ashx?la=en> (April 5, 2018). There is no documentation on the deadline for when modeling outages should be posted on the PJM website.

89 PJM's treatment of transmission outages in the FTR models is discussed in the *2019 Quarterly State of the Market Report for PJM: January through September*, Section 13: FTRs and ARRs: Supply and Demand.

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

| | | 2018/2019 (12 months) | | | | 2019/2020 (7 months) | | | |
|---|---|---|---|---|---|---|---|---|---|
| Received Status | Planned Duration | Emergency | Non Emergency | Total | Percent Non Emergency | Emergency | Non Emergency | Total | Percent Non Emergency |
| On Time | <2 weeks | 0 | 19 | 19 | 100.0% | 0 | 8 | 8 | 100.0% |
| | >=2 weeks & <2 months | 0 | 65 | 65 | 100.0% | 0 | 51 | 51 | 100.0% |
| | >=2 months | 0 | 115 | 115 | 100.0% | 0 | 87 | 87 | 100.0% |
| | Total | 0 | 199 | 199 | 100.0% | 0 | 146 | 146 | 100.0% |
| Late | <2 weeks | 0 | 3 | 3 | 100.0% | 0 | 3 | 3 | 100.0% |
| | >=2 weeks & <2 months | 0 | 9 | 9 | 100.0% | 0 | 5 | 5 | 100.0% |
| | >=2 months | 1 | 27 | 28 | 96.4% | 2 | 24 | 26 | 92.3% |
| | Total | 1 | 39 | 40 | 97.5% | 2 | 32 | 34 | 94.1% |

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. Of all the annual FTR market modeled outages expected to occur in the first seven months of the 2019/2020 planning period and submitted late, 14.7 percent (5 out of 34) were expected to cause congestion Overall, none of all the annual FTR market modeled outages expected to occur in the 2018/2019 planning period and submitted late were expected to cause congestion.

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

| | | 2018/2019 (12 months) | | | | 2019/2020 (7 months) | | | |
|---|---|---|---|---|---|---|---|---|---|
| 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 | 10 | 9 | 19 | 52.6% | 4 | 4 | 8 | 50.0% |
| | >=2 weeks & <2 months | 17 | 48 | 65 | 26.2% | 20 | 31 | 51 | 39.2% |
| | >=2 months | 30 | 85 | 115 | 26.1% | 18 | 69 | 87 | 20.7% |
| | Total | 57 | 142 | 199 | 28.6% | 42 | 104 | 146 | 28.8% |
| Late | <2 weeks | 0 | 3 | 3 | 0.0% | 2 | 1 | 3 | 66.7% |
| | >=2 weeks & <2 months | 0 | 9 | 9 | 0.0% | 2 | 3 | 5 | 40.0% |
| | >=2 months | 0 | 28 | 28 | 0.0% | 1 | 25 | 26 | 3.8% |
| | Total | 0 | 40 | 40 | 0.0% | 5 | 29 | 34 | 14.7% |

Table 12-55 shows that 25.0 percent of outage requests modeled in the annual FTR market for the first seven months of the 2019/2020 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 25.7 percent for the 2018/2019 planning period. Table 12-55 also shows that 22.1 percent of outages requests modeled in the Annual FTR Market for the first seven months of the 2019/2020 planning period and with a duration of two months or longer were cancelled, compared to 23.1 percent for the 2018/2019 planning period.

### Table 12-55 Annual FTR market modeled transmission facility outage requests by processed status: June 2018 through December 2019

| | | 2018/2019 (12 months) | | 2019/2020 (7 months) | |
|---|---|---|---|---|---|
| Planned Duration | Processed Status | Outage Requests | Percent | Outage Requests | Percent |
| <2 weeks | In Progress | 2 | 9.1% | 0 | 0.0% |
| | Denied | 0 | 0.0% | 0 | 0.0% |
| | Approved | 1 | 4.5% | 0 | 0.0% |
| | Cancelled | 4 | 18.2% | 1 | 9.1% |
| | Active | 0 | 0.0% | 0 | 0.0% |
| | Completed | 15 | 68.2% | 10 | 90.9% |
| | Total | 22 | 100.0% | 11 | 100.0% |
| >=2 weeks & <2 months | In Progress | 7 | 9.5% | 10 | 17.9% |
| | Denied | 0 | 0.0% | 0 | 0.0% |
| | Approved | 0 | 0.0% | 0 | 0.0% |
| | Cancelled | 19 | 25.7% | 14 | 25.0% |
| | Active | 0 | 0.0% | 0 | 0.0% |
| | Completed | 48 | 64.9% | 32 | 57.1% |
| | Total | 74 | 100.0% | 56 | 100.0% |
| >=2 months | In Progress | 20 | 14.0% | 17 | 15.0% |
| | Denied | 1 | 0.7% | 0 | 0.0% |
| | Approved | 1 | 0.7% | 1 | 0.9% |
| | Cancelled | 33 | 23.1% | 25 | 22.1% |
| | Active | 3 | 2.1% | 27 | 23.9% |
| | Completed | 85 | 59.4% | 43 | 38.1% |
| | Total | 143 | 100.0% | 113 | 100.0% |

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the first seven months of the 2019/2020 planning period, 180 outage requests were modeled and 11,895 outage requests were not modeled in the Annual FTR Market. In the 2018/2019 planning period, 239 outage requests were modeled and 21,853 outage requests were not modeled in the Annual FTR Market.

Table 12-56 shows that 6.3 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labeled On Time according to the rules, were submitted after the Annual FTR Auction bidding opening date for the first seven months of the 2019/2020 planning period compared to 13.4 percent in the 2018/2019 planning period.

### Table 12-56 Transmission facility outage requests not modeled in Annual FTR Auction: June 2018 through December 2019

| | 2018/2019 (12 months) | | | | | | 2019/2020 (7 months) | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 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 | 1,714 | 8,459 | 83.2% | 219 | 8,556 | 97.5% | 1,555 | 3,749 | 70.7% | 193 | 4,569 | 95.9% |
| >=2 weeks & <2 months | 642 | 372 | 36.7% | 163 | 907 | 84.8% | 514 | 124 | 19.4% | 124 | 493 | 79.9% |
| >=2 months | 219 | 34 | 13.4% | 204 | 364 | 64.1% | 165 | 11 | 6.3% | 202 | 196 | 49.2% |
| Total | 2,575 | 8,865 | 77.5% | 586 | 9,827 | 94.4% | 2,234 | 3,884 | 63.5% | 519 | 5,258 | 91.0% |

Table 12-57 shows that 56.6 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 seven months of the 2019/2020 planning period. It also shows that 83.2 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were approved and completed in the 2018/2019 planning period.

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

| | 2018/2019 (12 months) | | | 2019/2020 (7 months) | | |
|---|---|---|---|---|---|---|
| Planned Duration | Completed Outages | Total | Percent Complete | Completed Outages | Total | Percent Complete |
| <2 weeks | 7,078 | 8,556 | 82.7% | 3,876 | 4,569 | 84.8% |
| >=2 weeks & <2 months | 784 | 907 | 86.4% | 389 | 493 | 78.9% |
| >=2 months | 303 | 364 | 83.2% | 111 | 196 | 56.6% |
| Total | 8,165 | 9,827 | 83.1% | 4,376 | 5,258 | 83.2% |

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 those 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.[90] Table 12-58 and Table 12-59 show the summary information on outage requests modeled in the Monthly Balance of

90 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).

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.

Table 12-58 shows that on average, 35.0 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the first seven months of the 2019/2020 planning period. On average, 29.8 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2018/2019 planning period.

### Table 12-58 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: June 2018 through December 2019

| | 2018/2019 | | | | 2019/2020 | | | |
|---|---|---|---|---|---|---|---|---|
| Month | On Time | Late | Total | Percent Late | On Time | Late | Total | Percent Late |
| Jun | 208 | 106 | 314 | 33.8% | 162 | 115 | 277 | 41.5% |
| Jul | 136 | 71 | 207 | 34.3% | 92 | 96 | 188 | 51.1% |
| Aug | 137 | 78 | 215 | 36.3% | 131 | 86 | 217 | 39.6% |
| Sep | 465 | 136 | 601 | 22.6% | 379 | 147 | 526 | 27.9% |
| Oct | 536 | 191 | 727 | 26.3% | 533 | 183 | 716 | 25.6% |
| Nov | 391 | 129 | 520 | 24.8% | 431 | 163 | 594 | 27.4% |
| Dec | 363 | 129 | 492 | 26.2% | 311 | 146 | 457 | 31.9% |
| Jan | 199 | 90 | 289 | 31.1% | | | | |
| Feb | 213 | 109 | 322 | 33.9% | | | | |
| Mar | 389 | 146 | 535 | 27.3% | | | | |
| Apr | 427 | 159 | 586 | 27.1% | | | | |
| May | 362 | 181 | 543 | 33.3% | | | | |
| Average | 319 | 127 | 446 | 29.8% | 291 | 134 | 425 | 35.0% |

Table 12-59 shows that on average, 19.0 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the first seven months of the 2019/2020 planning period. On average, 20.0 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2018/2019 planning period.

### Table 12-59 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: June 2018 through December 2019

| Planning Year | Month | In Process | Denied | Approved | Cancelled | Revised | Active | Complete | Total | Percent Cancelled |
|---|---|---|---|---|---|---|---|---|---|---|
| 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% |
| | Apr | 51 | 0 | 13 | 89 | 0 | 170 | 263 | 586 | 15.2% |
| | May | 38 | 4 | 8 | 119 | 0 | 137 | 237 | 543 | 21.9% |
| | Avg | 40 | 5 | 10 | 89 | 0 | 123 | 178 | 446 | 20.0% |
| 2019/2020 | Jun | 17 | 2 | 2 | 47 | 0 | 82 | 127 | 277 | 17.0% |
| | Jul | 13 | 4 | 0 | 45 | 0 | 72 | 54 | 188 | 23.9% |
| | Aug | 14 | 5 | 0 | 37 | 0 | 79 | 82 | 217 | 17.1% |
| | Sep | 58 | 2 | 25 | 93 | 0 | 178 | 170 | 526 | 17.7% |
| | Oct | 65 | 2 | 13 | 131 | 1 | 200 | 304 | 716 | 18.3% |
| | Nov | 30 | 1 | 11 | 120 | 0 | 173 | 259 | 594 | 20.2% |
| | Dec | 27 | 4 | 8 | 86 | 1 | 74 | 257 | 457 | 18.8% |
| | Avg | 32 | 3 | 8 | 80 | 0 | 123 | 179 | 425 | 19.0% |

Table 12-60 shows that on average, 9.4 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 seven months of the 2019/2020 planning period, compared to 10.9 percent in the 2018/2019 planning period. On average, 67.4 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 seven months of the 2019/2020 planning period, compared to 68.6 percent in the 2018/2019 planning period.

### Table 12-60 Transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction: June 2018 through December 2019

| | 2018/2019 | | | | | | 2019/2020 | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 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 | 757 | 120 | 13.7% | 400 | 819 | 67.2% | 678 | 81 | 10.7% | 337 | 704 | 67.6% |
| Jul | 393 | 64 | 14.0% | 272 | 642 | 70.2% | 392 | 63 | 13.8% | 268 | 729 | 73.1% |
| Aug | 483 | 68 | 12.3% | 259 | 715 | 73.4% | 357 | 44 | 11.0% | 300 | 640 | 68.1% |
| Sep | 819 | 145 | 15.0% | 283 | 712 | 71.6% | 901 | 117 | 11.5% | 318 | 661 | 67.5% |
| Oct | 1,230 | 118 | 8.8% | 329 | 945 | 74.2% | 1,115 | 115 | 9.3% | 388 | 929 | 70.5% |
| Nov | 867 | 79 | 8.4% | 406 | 860 | 67.9% | 1,003 | 60 | 5.6% | 459 | 657 | 58.9% |
| Dec | 663 | 44 | 6.2% | 321 | 672 | 67.7% | 769 | 31 | 3.9% | 330 | 634 | 65.8% |
| Jan | 553 | 76 | 12.1% | 369 | 726 | 66.3% | | | | | | |
| Feb | 639 | 103 | 13.9% | 328 | 740 | 69.3% | | | | | | |
| Mar | 1,081 | 123 | 10.2% | 380 | 772 | 67.0% | | | | | | |
| Apr | 1,397 | 104 | 6.9% | 438 | 749 | 63.1% | | | | | | |
| May | 1,243 | 131 | 9.5% | 444 | 854 | 65.8% | | | | | | |
| Avg | 844 | 98 | 10.9% | 352 | 767 | 68.6% | 745 | 73 | 9.4% | 343 | 708 | 67.4% |

Table 12-61 shows that on average, 71.4 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 seven months of 2019/2020 planning period, compared to 68.6 percent in the 2018/2019 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 2018 through December 2019

| | 2018/2019 | | | 2019/2020 | | |
|---|---|---|---|---|---|---|
| | Completed Outages | Total | Percent Complete | Completed Outages | Total | Percent Complete |
| Jun | 625 | 819 | 76.3% | 534 | 704 | 75.9% |
| Jul | 449 | 642 | 69.9% | 489 | 729 | 67.1% |
| Aug | 506 | 715 | 70.8% | 500 | 640 | 78.1% |
| Sep | 480 | 712 | 67.4% | 455 | 661 | 68.8% |
| Oct | 614 | 945 | 65.0% | 616 | 929 | 66.3% |
| Nov | 570 | 860 | 66.3% | 472 | 657 | 71.8% |
| Dec | 468 | 672 | 69.6% | 469 | 634 | 74.0% |
| Jan | 471 | 726 | 64.9% | | | |
| Feb | 470 | 740 | 63.5% | | | |
| Mar | 568 | 772 | 73.6% | | | |
| Apr | 504 | 749 | 67.3% | | | |
| May | 586 | 854 | 68.6% | | | |
| Avg | 526 | 767 | 68.6% | 505 | 708 | 71.4% |

## 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.[91]

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.

91 PJM. "Manual 3: Transmission Operations," Rev. 56 (Dec. 5, 2019).

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

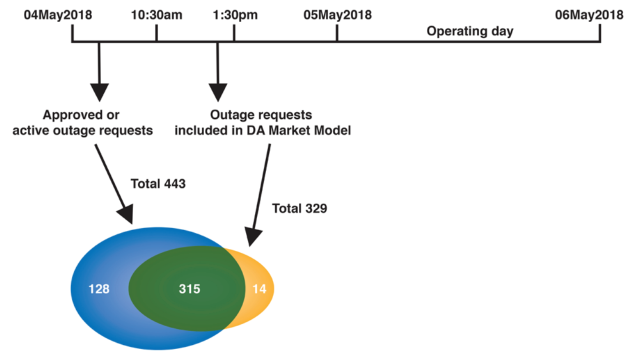



Figure 12-5 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.

### Figure 12-5 Approved or active outage requests: January 2015 through December 2019

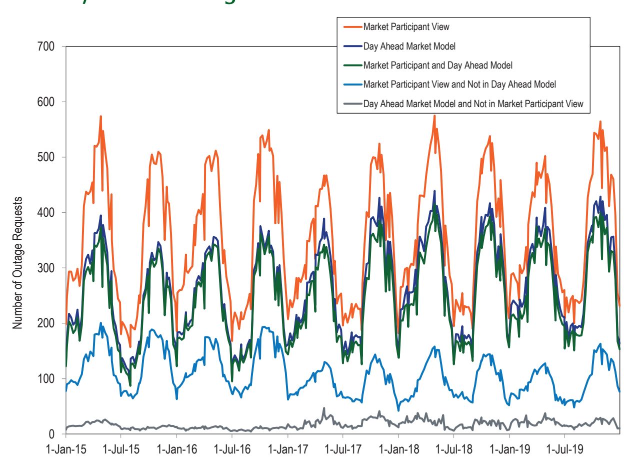


Figure 12-6 compares the weekly average number of outages included as inputs to the day-ahead market by PJM with the outages that actually occurred during the operating day.

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

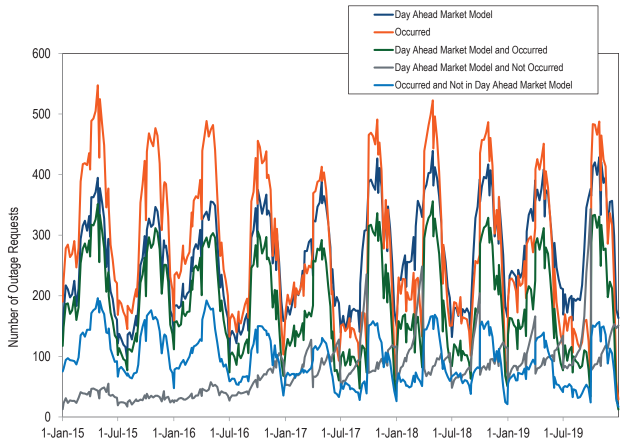



Figure 12-7 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

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

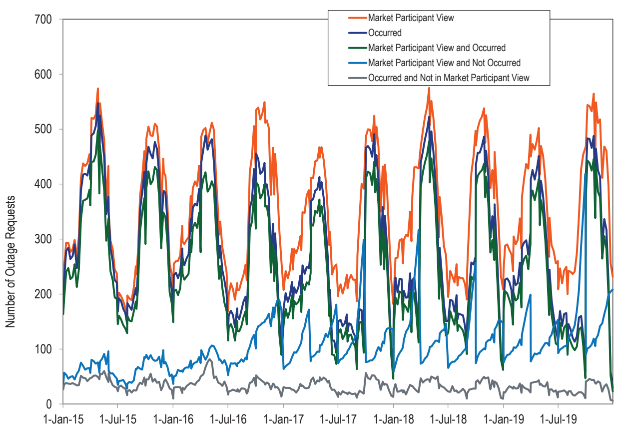



Figure 12-5, Figure 12-6, and Figure 12-7 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or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