Generation and Transmission Planning

Overview[1]

Generation Interconnection Planning

Existing Generation Mix

- As of December 31, 2025, PJM had a total installed capacity of 202,424.8 MW, of which 38,366.4 MW (19.0 percent) are coal fired steam units, 57,047.7 MW (28.2 percent) are combined cycle units and 33,452.6 MW (16.5 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- Of the 202,424.8 MW of installed capacity, 75,482.0 MW (37.3 percent) are from units older than 40 years, of which 30,814.3 MW (40.8 percent) are coal fired steam units, 255.0 MW (0.3 percent) are combined cycle units and 25,550.6 MW (33.8 percent) are nuclear units.

Generation Retirements[2]

- As of December 31, 2025, there were 64,081.0 MW of generation that have been, or are planned to be, retired between 2011 and 2031, of which 46,526.8 MW (72.6 percent) are coal fired steam units.
- In 2025, 1,000.3 MW of generation retired. The largest generator that retired in 2025 was the 410.0 MW Indian River 4 coal fired steam unit located in the DPL Zone. Of the 1,000.3 MW of generation that retired in 2025, 410.0 MW (41.0 percent) were located in the DPL Zone.
- As of December 31, 2025, there were 8,335.4 MW of generation that have requested retirement after December 31, 2025, of which 2,620.0 MW (31.4 percent) are located in the AEP Zone. Of the generation requesting retirement in the AEP Zone, 2,620.0 MW (100.0 percent) are coal fired steam units.

Generation Queue

New Service Requests Serial Process[3]

- On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions to improve the queue process.[4] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out serial processing method.[5] This change will allow projects to move forward based on a first ready/first out analysis, where readiness is demonstrated through site control and financial milestones and there is an option to exit the study process early based on system impacts. The transition to the new queue process began on July 10, 2023.
- There were 8,190 generation request projects submitted in the new service request serial process queue from 1997 until the implementation of the new cycle process on July 10, 2023. As a result of the transition to the new services cycle process, 312 projects were moved to transition cycle 1 (TC1). There were 1,347 projects eligible to resubmit for evaluation in transition cycle 2 (TC2). Of those 1,347 eligible projects, 550 projects resubmitted and are now being evaluated in TC2. Of the 1,347 eligible projects, 797 projects did not resubmit, and were withdrawn from the queue. There were 1,070 projects initially entered into the AH2 queue and beyond. Those 1,070 projects are now considered invalid and have been removed from the queue. As a result of the transition to the cycle process, the 8,190 projects in the serial process queue have been reduced to 5,461 projects. Projects that will be evaluated in TC1 and TC2, and those projects no longer eligible to be evaluated in the serial process have been removed from the new service requests serial process metrics. New service requests cycle process metrics are reported separately from the serial process metrics.
- As of December 31, 2025, a total of 41,528.9 MW, on an energy basis, were in generation request serial service queues in the status of active, under construction or suspended.[6] Based on historical

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," (Accessed on December 31, 2025) <https://www.pjm.com/planning/service-requests/gen-deactivations>.
3 See PJM. Planning. "Serial Service Request Status," (Accessed on December 31, 2025) <https://www.pjm.com/planning/service-requests/serial-service-request-status>.
4 See 181 FERC ¶ 61,162 (2022).
5 See "Interconnection Process Reform," presented at April 27, 2022 meeting of the Members Committee. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.
6 Unless otherwise noted, the queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.

completion rates, 22,140.7 MW (53.3 percent), on an energy basis, of new generation in the queue are expected to go into service. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service.

- Of the 5,312.5 MW, on an energy basis, of thermal projects (including combined cycle, CT natural gas and coal fired steam projects) in the serial queue, 3,770.5 MW (71.0 percent) are expected to go in service based on historical completion rates as of December 31, 2025.
- Of the 3,106.1 MW, on an energy basis, of battery projects in the serial queue, only 816.7 MW (26.3 percent) are expected to go in service based on historical completion rates as of December 31, 2025.
- Of the 33,066.3 MW, on an energy basis, of renewable projects in the serial queue, 17,530.9 MW (53.0 percent) are expected to go in service based on historical completion rates as of December 31, 2025.
- Of the 5,140.6 MW, on a capacity basis that requested CIRs, of thermal projects (including combined cycle, CT natural gas and coal fired steam projects) requested in the generation serial queues in the status of active, under construction or suspended, 3,585.9 MW (69.8 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction,[7] the 5,140.6 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 2,551.4 MW of capacity (49.6 percent of the total requested capacity).[8]
- Of the 2,098.3 MW, on a capacity basis that requested CIRs, of battery projects requested in the generation serial queues in the status of active, under construction or suspended, 143.9 MW (6.9 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 2,098.3 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 83.5 MW of capacity (4.0 percent of the total requested capacity).
- Of the 17,088.7 MW, on a capacity basis that requested CIRs, of renewable projects requested in the serial generation queues in the status of active, under construction or suspended, 9,061.2 MW (53.0 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 17,088.7 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 903.0 MW of capacity (5.3 percent of the total requested capacity).
- As of December 31, 2025, 24,371.6 MW of capacity requests (requested CIRs) were in the generation serial queues in the status of active, under construction or suspended. Based on historical completion rates, 12,813.1 MW (52.6 percent) are expected to go into service. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 24,371.6 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 3,558.9 MW of capacity (14.6 percent of the total requested capacity).
- As of December 31, 2025, 5,461 projects, representing 609,262.3 MW, have entered the serial queue process since its inception. Of those, 1,276 projects, representing 94,866.2 MW (15.6 percent of the MW), went into service. Of the projects that entered the serial queue process, 3,750 projects, representing 472,867.2 MW (77.6 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.
- In 2025, 2,492.7 MW from the serial queue went into service. Of the 2,492.7 MW that went in service, 2,208.8 MW (88.6 percent) were solar units, 254.9 MW (10.2 percent) were wind units and 29.0 MW (1.2 percent) were coal fired steam units.

7 Unless otherwise noted, the ELCC derate factors in this section are based on the *ELCC Class Ratings for 2027/2028 Base Residual Auction*, PJM Interconnection L.L.C. (August 1, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2027-28-bra-elcc-class-ratings.pdf>.

8 Unless otherwise noted, the ELCC derate adjusted MW are calculated using the 2027/2028 Base Residual Auction ELCC factors. The adjusted MW are calculated using the four hour storage ELCC derate for battery resources, tracking solar for solar resources and onshore wind for wind resources.

- Of the 2,809 projects that entered the serial queue from January 1, 2015, through July 10, 2023, 2,062 projects (73.4 percent) were renewable. Of the 690 projects that entered the serial queue in 2020, 545 projects (79.0 percent) were renewable. Renewable projects make up 85.7 percent of all projects in the serial queue and account for 79.6 percent of the nameplate MW currently active, suspended or under construction in the serial queue as of December 31, 2025.
- On December 31, 2025, 30,081.4 MW, on an energy basis, were in generation request serial queues that had reached the construction service agreement milestone or equivalent, in the status of active, suspended or under construction. Of the 30,081.4 MW, 10,916.9 MW (36.3 percent) had not begun construction, 9,889.1 MW (32.9 percent) had begun construction, but are now suspended, and 9,275.4 MW (30.8 percent) are currently under construction. Reaching the final milestone required prior to construction does not mean a project will immediately begin construction or even that it necessarily will ever begin construction.

New Service Requests Cycle Process[9]

Transition Cycle 1 (TC1)

- Transition cycle 1 (TC1) is comprised of 312 proposed generation projects. Those projects make up 40,650.1 MW. On December 31, 2025, all projects in TC1 were either in the status of active or were withdrawn from the cycle. Of the 40,650.1 MW in TC1, 14,897.2 MW (36.6 percent) were active and 25,752.9 MW (63.4 percent) were withdrawn.
- On December 31, 2025, there were 14,897.2 MW, on an energy basis, of which 7,285.6 MW are on a capacity basis that requested CIRs, in TC1 in the status of active.
- Of the 7,285.6 MW, on a capacity basis that requested CIRs in TC1 in the status of active, 1,901.4 MW (26.1 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 569 MW, on a capacity basis that requested CIRs, of thermal projects (including CT natural gas projects) requested in TC1 in the status of active, 347.1 MW (61.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 3,837.9 MW, on a capacity basis that requested CIRs, of solar projects requested in TC1 in the status of active, 307.0 MW (8.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 1,353.3 MW, on a capacity basis that requested CIRs, of battery projects requested in TC1 in the status of active, 784.9 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 5,363.3 MW, on a capacity basis that requested CIRs, of renewable projects requested in TC1 in the status of active, 769.3 MW (14.3 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Transition Cycle 2 (TC2) and Reliability Resource Initiative (RRI)

- On December 13, 2024, PJM submitted modifications to its Open Access Transmission Tariff to add provisions, through a one-time reliability based expansion of the projects in TC2.[10] On February 11, 2025, the Commission approved the RRI tariff modifications.[11] The proposed RRI Tariff revisions created a second TC2 application window that enabled RRI projects to join TC2 and be studied for interconnection during the transition period.
- PJM received 97 applications (28.6 GW) of RRI projects during the RRI application window. Of these projects, 48 involved uprates, in which existing resources are modified to increase the economic maximum generation capability, and 49 proposed building new generation. PJM reviewed the submitted RRI projects using the Commission approved scoring criteria, and approved 51 projects (11,577.4 MW).[12] On December 31, 2025, all RRI projects were either in the status of active or withdrawn from the cycle. Of the 11,577.4 MW of

9 See PJM. Planning. "Cycle Service Request Status," (Accessed on December 31, 2025) <https://www.pjm.com/planning/m/cycle-service-request-status>.

10 See *PJM Interconnection L.L.C.* Docket No. ER25-712 (December 13, 2024).

11 190 FERC ¶ 61,084 (February 11, 2025).

12 The RRI proposal was to select the top 50 projects using the approved scoring criteria. The implemented scoring criteria resulted in a tie for the 50th project. This resulted in PJM selecting 51 projects as part of the RRI process.

approved RRI projects, 7,951.4 MW (68.7 percent) were active and 3,626.0 MW (31.3 percent) were withdrawn.

- Transition cycle 2 (TC2) is comprised of 647 proposed generation projects. TC2 includes 550 projects submitted during the TC2 window, and 97 projects submitted through the RRI window. Those projects make up 78,451.4 MW. On December 31, 2025, all projects in TC2 were either in the status of active or were withdrawn from the cycle. Of the 78,451.4 MW in TC2, 30,542.4 MW (38.9 percent) were active and 47,909.0 MW (61.1 percent) were withdrawn.
- On December 31, 2025, there were 30,542.4 MW, on an energy basis, of which 22,330.0 MW are on a capacity basis that requested CIRs, in TC2 in the status of active.
- Of the 22,330.0 MW, on a capacity basis that requested CIRs in TC2 in the status of active, 10,233.0 MW (45.8 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 7,392.9 MW, on a capacity basis that requested CIRs, of thermal projects (including combined cycle and CT natural gas projects) requested in TC2 in the status of active, 5,374.8 MW (72.7 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 6,507.0 MW, on a capacity basis that requested CIRs, of solar projects requested in TC2 in the status of active, 520.6 MW (8.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 4,981.3 MW, on a capacity basis that requested CIRs, of battery projects requested in TC2 in the status of active, 2,889.2 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 8,635.8 MW, on a capacity basis that requested CIRs, of renewable projects requested in TC2 in the status of active, 717.3 MW (8.3 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Cycle Process Totals[13]

- On December 31, 2025, there were 959 proposed generation projects in the new services cycle process queues. Those projects make up 119,101.5 MW. On December 31, 2025, all projects in the cycle process queues were either in the status of active or were withdrawn. Of the 119,101.5 MW in the cycle process queues, 45,439.7 MW (38.2 percent) were active and 73,661.8 MW (61.8 percent) were withdrawn.
- On December 31, 2025, there were 45,439.7 MW, on an energy basis, of which 29,615.6 MW are on a capacity basis that requested CIRs, in cycle process queues in the status of active.
- Of the 29,615.6 MW, on a capacity basis that requested CIRs in the cycle process queues in the status of active, 12,134.4 MW (41.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 7,961.1 MW, on a capacity basis that requested CIRs, of thermal projects (including combined cycle and CT natural gas projects) requested in cycle process queues in the status of active, 5,721.9 MW (71.9 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 10,344.9 MW, on a capacity basis that requested CIRs, of solar projects requested in cycle process queues in the status of active, 827.6 MW (8.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.
- Of the 6,334.6 MW, on a capacity basis that requested CIRs, of battery projects requested in cycle process queues in the status of active or under construction, 3,674.1 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

13 As of December 31, 2025, the cycle process totals include those projects included in TC1 and TC2.

- Of the 13,999.1 MW, on a capacity basis that requested CIRs, of renewable projects requested in cycle process queues in the status of active or under construction, 1,486.7 MW (10.6 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

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. If done correctly and if FTRs/ARRs returned 100 percent of congestion to load, the benefit/cost analysis would include the total net change in production costs and would not include congestion. In addition, PJM's benefit/cost analysis includes only the decreases in costs to load and ignores the increases in costs to load associated with market efficiency projects.
- Through December 31, 2025, PJM has completed six market efficiency cycles under Order No. 1000.[14] In February 2024, PJM completed the 2024/2025 market efficiency base case. In May 2024, PJM posted the 2024/2025 Market Efficiency planning assumptions. The long term market efficiency window opened on April 11, 2025, and closed on June 10, 2025. This window accepted proposals to address historical congestion on three identified flowgates. PJM received 14 proposals from five entities. Two projects, submitted by incumbent transmission owners, were selected as the preferred solutions.[15] These projects will be presented to the PJM Board for approval in the first quarter of 2026. There were no projects selected for acceleration in the 2024/2025 Market Efficiency window.

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.
- The simultaneous use for joint projects of an incorrectly defined benefit/cost method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO projects to PJM participants and in some cases approval of projects that do not pass a correctly defined benefit/cost test.

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.

PJM MISO Interregional Transfer Capability Study (ITCS)

- PJM and MISO developed the Interregional Transfer Capability Study (ITCS) to help identify potential transmission projects that could incrementally improve the systems' ability to mitigate constraints, improve market efficiency, respond to extreme weather and increase interregional transfer capability.

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."[16] Supplemental projects are exempt from competition.

14 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).

15 One of the three identified congestion drivers included in the 2024/2025 Market Efficiency window was addressed in the 2025 RTEP Window 1.

16 See PJM. "Transmission Construction Status," (Accessed on December 31, 2025) <https://www.pjm.com/planning/m/project-construction>.

- The average number of supplemental projects expected in each in service year increased by 1,105.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 241 for years 2008 through 2025 (post Order 890).[17]

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. End of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to require competition to build the project. Under the current approach, end of life projects are excluded from the RTEP process and exempt from competition.

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) reviews proposals to improve transmission reliability in PJM and between PJM and neighboring regions. 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.[18] In 2025, the PJM Board approved $8.5 billion in upgrades. As of December 31, 2025, the PJM Board has approved $58.5 billion in system enhancements since 1999.

Transmission Competition

- The MMU makes several recommendations related to the competitive transmission planning process. The recommendations include improved process transparency, incorporation of competition between transmission and generation alternatives, and the removal of barriers to competition from nonincumbent transmission. These recommendations 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, financed and built by market participants, 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, 2025, no QTUs have cleared a Base Residual Auction or an Incremental Auction.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When a reportable transmission facility needs 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.[19]
- There were 16,246 transmission outage requests submitted in the first seven months of the 2025/2026 planning period. Of the requested outages, 70.8 percent were planned for less than or equal to five days and 11.6 percent were planned for greater than 30 days. Of the requested outages, 34.3 percent were late according to the rules in PJM's Manual 3.

17 See *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

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

19 See "PJM Manual 03: Transmission Operations," Rev. 69 (November 20, 2025).

Recommendations

Generation Retirements

- The MMU recommends that CIRs should end on the date of retirement in order to help ensure competitive markets and competitive access to the grid. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors or to exercise market power by requiring high payments for CIRs.[20] (Priority: Medium. First reported 2013. Status: Partially adopted, 2012.)

Generation Queue

- Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data. PJM does not update this data. (Priority: High. First reported 2023. Not adopted.)
- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM establish an expedited PJM managed queue process to identify commercially viable projects that could help eliminate or reduce the need for specific RMRs or that could address specific reliability needs and allow the identified projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: High. First reported 2024. 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 an expedited 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.[21] (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.[22] (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 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 changes in production costs but not congestion costs, including increased costs to load and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are used for defining benefits. The MMU also recommends that, if the market efficiency process is retained, market efficiency projects that fail to meet PJM benefit/cost criteria in a Schedule 6 annual reevaluation, prior to construction commencing or prior to state approval, be canceled and removed from further consideration. (Priority: Medium. First reported 2018. Status: Not adopted.)

Comparative Cost Framework

- The MMU recommends that PJM modify the project proposal templates to include data necessary to

20 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>.

21 PJM Filing, FERC Docket No. ER22-2110-000 (June 14, 2022); 181 FERC ¶ 61,162 (2022).

22 Ibid.

perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life. (Priority: Medium. First reported 2020. 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 require competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted. Rejected by FERC.)[23]
- 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 be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to require competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)[24]
- 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 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 require 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 require 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 storage resources not be includable as transmission assets for any reason. (Priority: High. First reported 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution based dfax allocation method is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact

23 The FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).

24 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), *affirmed*, American Municipal Power, Inc., et al. v. FERC, Case No. 20-1449 (D.C. Cir. November 17, 2023), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).

on the transmission facilities.[25] (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 and that all PJM transmission owners implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2019. Status: Partially adopted.)
- The MMU recommends that all PJM transmission owners investigate the applicability and potential cost savings of Grid Enhancing Technology (GET) and that all PJM transmission owners implement cost effective GET, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2024. Status: Not adopted.)
- The MMU recommends that the implementation of Grid Enhancing Technology (GET) be opened to competition from third parties, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2024. 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, create options for late requests based on the reasons, and apply the modified rules for late submissions to any such outages. The MMU recommends that PJM create options for treatment of late outages. The current rules apply more stringent rules, based on controlling actions, to late outages without distinguishing among reasons for late outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a definition of the economic and physical congestion analysis required for transmission outage requests and associated triggers, including both the extent of overloaded facilities and the level of economic congestion, to include in PJM manuals after appropriate review with appropriate rules for on time and late outage requests. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM create options for late requests based on the reasons, and modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date, based on those options. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Conclusion

The goal of the PJM market design should be to enhance competition and to ensure that competition is the core element of all PJM markets. 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. When generating units retire or load increases, there is no market mechanism in place that would require or even permit 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 require 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 MMU recognizes that the Commission has issued orders that are inconsistent with the recommendations of the MMU and that PJM cannot unilaterally modify those directives. It remains the recommendation of the MMU that 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 the reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process

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

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. Rigorous standards that protect customers from risk should be applied to competitive transmission suppliers to ensure that customers receive the benefits of competition.

Order No. 1000 removed the right of first refusal (ROFR) for transmission projects for incumbent transmission owners except for the case of supplemental projects. This created an incentive for incumbent transmission owners to designate projects as supplemental projects to avoid the Order No. 1000 competitive provisions. Two PJM states, Indiana and Michigan, have passed laws that provide ROFR to incumbent utilities/transmission owners.[26] [27]

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. Line ratings should be provided for a range of durations to ensure that operators understand the actual impact of short term flows versus longer term flows when making decisions that affect market prices. 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. New technologies that permit dynamic line ratings (DLR) should be implemented. All PJM Transmission Owners should be required to immediately adopt current dynamic line rating (DLR) methods for all transmission facilities, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC.

Given the slow pace of adoption by Transmission Owners of Grid Enhancing Technologies (GETs), PJM and the Commission should introduce rules that would allow third parties to propose adding GETs to the transmission system, subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. The third parties would be compensated in the same way that TOs would be compensated for comparable investments.

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. 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.

It would be antithetical to competition to permit transmission owners to own black start units under the backstop rules, to own batteries (storage as a transmission asset) or to permit transmission owners to build new generation, all under the antiquated cost of service regulation rules that were displaced by more efficient competitive markets. Such an approach would undermine competitive markets and require market projects built with investors' capital at risk to compete with subsidized resources.

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 require competition to build the project. If there is no defined need for a supplemental project for reliability, economic efficiency or operational performance then the project should not be included in rates.

Managing the generation queues is a complex process. The PJM queue evaluation process is being significantly improved, based on the proposal submitted by PJM on June 14, 2022, and approved by FERC on November 29, 2022.[28] [29] The new rules include significant modifications to the interconnection process designed to address some

26 See IN Code § 8-1-38-9, effective 7/1/2023. Applies to transmission facilities approved for construction through an RTO planning process. Incumbent Transmission Owner must exercise within 90 days.
27 See MCL §460.593, effective 12/17/2021. Applies to regionally cost shared transmission lines included in a plan adopted by a recognized planning authority. Must be exercised by the incumbent (s) within 90 days after plan is adopted/approved.
28 See *PJM*, Docket No. ER22-2110 (June 14, 2022).
29 See 181 FERC ¶ 61,162 (2022).

of the key underlying issues and significantly improve the efficiency of the process. These modifications include process efficiency enhancements, recognition of project clusters affecting the same transmission facilities, incentives to reduce the entry of speculative projects in the queue, and incentives to remove projects that are not expected to reach commercial operation. The new process should help to reduce backlog and to remove projects that are not viable earlier to help improve the overall efficiency of the queue process and to reduce uncertainty for new generation.

While the changes in the queue process will clearly improve the process, the MMU's recommendations related to the queue process will remain until the new process is fully in place and it can be evaluated. The impact of the modifications to the queue process will need to be evaluated to determine if they successfully remove projects from the queue if they are not viable, and allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress. There has been a significant reduction in queue projects. The behavior of project developers also creates issues with queue management. When developers put multiple projects in the queue to maintain their own optionality while planning to build only one they also affect all the projects that follow them in the queue. Project developers may also enter speculative projects in the queue and then put the project in suspended status while they address financing. The impacts of such behavior and the incentives for such behavior are addressed in the new process which includes nonrefundable fees, credit requirements, enhanced site control, elimination of the ability to suspend a project and milestone requirements. The impact of these aspects of the revised interconnection process should continue to be evaluated to ensure that they are having the desired effect on project developer behavior. Initial results from the transition cycles have shown that developers are withdrawing their projects at the specified decision points, which is helping to remove speculative projects from the queue process sooner. Whether the new cycle process will result in enough new dispatchable and renewable generation to meet system needs cannot be determined until after a full cycle has been completed, projects go in service and completion rates can be evaluated. 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 and whether transmission owners should perform interconnection studies.

The roles and efficiency of PJM, TOs and developers in the queue process all need to be examined and enhanced in order to help ensure that the queue process can function effectively and efficiently as the gateway to competition in the energy and capacity markets and not as a barrier to competition.

The Commission should require PJM, for example, to 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 while ensuring that customers receive the benefits of competition.

On January 31, 2025, PJM submitted revisions to the PJM Tariff to expedite the transfer of CIRs from deactivating generating resources to new replacement resources.[30] The Market Monitor filed opposing comments.[31] The Commission rejected the filing, finding (i) "that the lack of a maximum time limit for Commercial Operation Date extensions, which introduces the opportunity to delay commercial operation for an indefinite period of time, would result in a generator replacement process that does not promote the efficient interconnection of new resources;" and (ii) "because the unrestricted opportunity for a Replacement Generation Resource Project Developer to significantly delay commercial operation may result in CIRs and associated transmission capacity dedicated to accommodate the Replacement Generation Resource's operation going unused."[32] PJM has filed a new proposal for rule transferring CIRs to replacement resources which attempts to correct the deficiencies identified by FERC but continues to be flawed. [33]

The suggestion that generation owners should be permitted to avoid the queue process and directly transfer the generation CIRs to an affiliate or directly sell the CIRs to an unaffiliated entity should be rejected.[34]

30 See PJM Interconnection, L.L.C., Docket No. ER25-1128 (January 31, 2025).
31 See Comments of the Independent Market Monitor for PJM, Docket No. ER25-1128-000 (February 21, 2025).
32 192 FERC ¶ 61,137 at PP 38–39 (2025).
33 *See PJM Interconnection, L.L.C.*, Docket No. ER26-403-000 (October 31, 2025).
34 See PJM. "*Enhancing Capacity Interconnection Rights (CIR) Transfer Efficiency: Problem / Opportunity Statement*," <https://www.pjm.com/-/media/committees-groups/subcommittees/ips/2023/20230731/20230731-item-08b---enhancing-capacity-interconnection-rights---cir---transfer-efficiency-problem-statement.ashx>.

[35] This proposed approach is about creating a process to maximize the value of existing CIRs to incumbent generators and not about facilitating the efficient replacement of retiring resources. In effect, this approach, if adopted by the large number of retiring units, would create a chaotic, bilateral private queue process that would create market power and facilitate the exercise of market power in the sale of CIRs by incumbent generators. In effect, the proposed approach would replace a significant part of the recently redesigned PJM queue process. The proposed continuation of retention of CIRs by incumbent generators creates the potential for delays of up to a year and the proponents have proposed the option to request further delays. This approach would inappropriately delegate the authority from PJM to the incumbent generator to choose the new resource based on highest offer for CIRs rather than based on PJM defined system reliability needs. There would be no requirement to even be a capacity resource and there would be no requirement to offer the capacity into the capacity market. After the entire process, the contribution to PJM reliability could be zero. PJM's recently proposed expedited process for addressing reliability needs (RRI) is preferable and should be considered as the preferred alternative to the proposed approach from the Planning Committee stakeholder process.

The MMU recommends that PJM establish an expedited PJM managed queue process to identify commercially viable projects that could help eliminate or reduce the need for specific RMRs or that could address specific reliability needs and allow the identified projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. Rules should be developed to permit PJM to advance projects in the queue if they would resolve immediate reliability issues that result, for example, from unit retirements. The rules should be consistent with the flexibility included in the new queue process but add the option for PJM to expedite the interconnection and commercial operation of projects in the queue that would address identified reliability issues, consistent with the standing of the projects in the queue.

The PJM queue process should continue to define available and needed CIRs for all capacity queue projects. CIRs from retiring units should be made available to the next resource in the queue that can use them, on the retirement date of the retiring resource. Generation owners do not have property rights in CIRs. The value of CIRs is a result of the entire transmission system which has been paid for by customers and other generators. The value of CIRs is a result of the existence of a network and is not a result solely or even primarily of the investment that may or may not have been required in order to get CIRs. The cost of CIRs is part of project costs included in generation owners' investment decisions like any other project cost and subject to the same risk and reward structure. Open access to the transmission system by new resources should not be limited by claims to own the access rights by retiring units. In addition, the proposal to bypass the PJM interconnection process with a private, bilateral process ignores the fact that if the new resource is a renewable resource or a storage resource, the new resource does not have a capacity market must offer requirement. The PJM interconnection process could be bypassed, CIRs transferred and then the resource does not offer into the capacity market. In that case, scarce CIRs will be withheld by a generator who does not provide capacity and customers have to pay for an additional capacity resource instead.

The fundamental purpose of the queue process is to provide open access to the grid for supply resources. More specifically, the fundamental purpose of the queue process for capacity resources is to provide open access to the grid and to ensure that the energy from capacity resources is deliverable so that capacity resources can meet their must offer obligations in the energy market and provide reliable energy supply during all conditions.

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. However, 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.

35 On April 30, 2024, the CIR Transfer Efficiency issue was transferred from the Interconnection Process Subcommittee (IPS) to the Planning Committee (PC).

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. In addition, there are significant issues with PJM's current benefit/cost analysis which cause it to consistently overstate the potential benefits of market efficiency projects. The market efficiency process is misnamed. The MMU recommends that the market efficiency process be eliminated.

In addition, the use of an incorrectly defined cost-benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO transmission projects to PJM participants and in some cases approval of projects that do not pass a correctly defined benefit/cost test.

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 explicitly and incorrectly ignores the increased costs to load in zones that results from an RTEP project when calculating the energy market benefits. All increases and decreases in 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 benefit/cost 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 benefit/cost analysis.

Recent proposals from Transmission Owners to use storage as a transmission asset (SATA) raises a number of additional concerns about PJM's benefit/cost analysis. Storage is a market asset and should not be owned by transmission owners. PJM should not be evaluating SATA at all without a decision from FERC that SATA is allowable in PJM. At present, it is not allowed.

A significant flaw in PJM's benefit/cost analysis is that projected benefits are based on load forecasts which are currently dominated by projected large data center loads that are not verified by PJM and cannot be verified by PJM. That creates a bias towards finding transmission projects beneficial despite the fact that data center loads are imposing transmission costs on other customers as a result.

There are currently no market incentives for transmission owners to plan, 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 and that have large and unnecessary impacts on the PJM 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. The PJM process for evaluating the congestion impact of transmission outages needs to be clearly defined and upgraded to provide for management of transmission outages to minimize market impacts. The MMU continues to recommend that PJM draft a clear and expanded definition of the congestion analysis required for transmission outage requests that is incorporated in the PJM Market Rules. PJM Manual 38 currently defines congestion resulting from a transmission outage as an overload on transmission facilities rather than using the general economic definition of congestion resulting from out of merit generation to control constraints. PJM does not currently evaluate the economic impact of congestion when reviewing proposed transmission outages.[36]

The treatment by PJM and Dominion Virginia Power of the outage for the Lanexa – Dunnsville Line illustrates some of the issues with the current process. The outage

36 PJM, "Manual 38: Operations Planning," Rev. 19 (January 23, 2025) at 19-20.

was submitted and delayed more than once. PJM's analysis of expected congestion did not highlight the magnitude of the issue. Dominion Virginia Power did not stage the outage so as to minimize market disruption and congestion until after there were significant disruptions and congestion.

As an example of the complexities of defining the benefits of transmission investments, the reduction in congestion is frequently and incorrectly cited as a metric of benefits. Congestion is frequently misunderstood. Congestion is not static. Congestion exhibits dynamic intertemporal variability and dynamic locational variability. More importantly, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid. The correct metric is the total net change in production costs.

There is not a secular trend towards increasing congestion in PJM. Congestion is volatile on a monthly basis. Congestion is also volatile on an hourly and daily basis. For example, higher congestion can result from changes in seasonal and daily/hourly fuel costs.

The level and distribution of congestion at a point in time is a function of the location and size of generating units, the relative costs of the fuels burned and the associated marginal costs of generating units, the location and size of load and the locational capability of the transmission grid. Each of these factors changes over time.

The geographic distribution of congestion is dynamic. The nature and location of congestion in the PJM system has changed significantly over the last 10 years and continues to change. The nature and location of congestion in PJM can also change from one day to the next as a result of changes in relative fuel costs. As a result, building transmission to address a specific pattern of congestion does not make sense, unless the technology can be easily moved to new locations as conditions change. The transmission system is only one of many reasons that congestion exists. The dynamic nature of congestion and the multiple, interactive causes of congestion make it virtually impossible to identify the standalone impacts of an individual transmission investment on future congestion. It is possible, for example, that congestion occurring during a period of a few days in the winter as a result of very high fuel prices, significantly increases the reported level of congestion for the entire year. This has occurred in PJM. It would be a mistake to consider that level of congestion to be a signal to build transmission.

At a more fundamental level, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load. The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation, while only high cost generators are paid the high price at their bus and low cost generators are paid only the low price at their bus.

If FTRs worked perfectly and were assigned directly to load, FTRs would return all congestion to the load that paid the congestion. Congestion is not a cost, it is an accounting result of a market based on locational energy prices in which all load in a constrained area pays the higher single market clearing locational price, resulting in excess payments by load that are not paid to generation, which should be returned to load.

Counterintuitively, congestion actually increases when the transmission capacity between areas with lower cost generation and areas with higher cost generation increases but does not fully eliminate the need for some higher cost local generation. The smaller the amount of higher cost local generation needed to meet load, the more of the local load is met via low cost generation delivered over the transmission system and therefore the higher is the difference between what load pays and generation receives, congestion.

For all these reasons, if done correctly and if FTRs/ARRs returned 100 percent of congestion to load, the benefit/cost analysis for transmission projects would include the total net change in production costs and would not include congestion. The change in production costs correctly measures the changes in cost to load that result from a project.

The PJM Regional Transmission Expansion Plan (RTEP) successfully addresses the need for transmission investment to reliably meet load. Together with the requirement that new generation pay interconnection costs, the RTEP process has resulted in the appropriate level of new transmission investment in PJM. There is no evidence that the PJM planning process is not adequate to meet the requirements of the PJM markets. Additional transmission investment is not a panacea. Transmission investment is expensive and long lived and it is essential that transmission investments be carefully planned for clearly identified needs in order to ensure that power markets can continue to provide reliable service at a competitive price.

PJM must make out of market payments to units that want to retire (deactivate) but that PJM requires to remain in service, for limited operation, for a defined period because the unit is needed for reliability.[37] This provision has been known as Reliability Must Run (RMR) service but RMR is not defined in the PJM tariff. The correct term is Part V reliability service. The need to retain uneconomic units in service reflects a flawed market design and/or planning process problems. If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. The planning process should evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required in order to limit the duration of Part V service for individual units. It is essential that the deactivation provisions of the tariff be evaluated and modified. It is also essential that PJM look forward and attempt to plan for foreseeable unit retirements, whether for economic or regulatory reasons. PJM should consider an expedited queue process for projects that could replace the retiring capacity including the immediate transfer of the retiring unit's CIRs to units in the queue in order to permit generation to compete as an alternative to the current transmission only approach.

An area in northern Virginia in the Dominion Transmission Zone, known as Data Center Alley, has experienced significant load growth from data centers. Dominion has presented 44 supplemental project requests to serve the increase in load through the summer of 2025. As part of the supplemental planning process, PJM performs a do no harm analysis. PJM identified the need for additional baseline reinforcements to support the load growth. These baseline reinforcements were addressed in the 2022 RTEP Window 3, when the PJM board approved $1.4 billion of necessary baseline upgrades specific to the Data Center Alley reinforcements.[38] These regional transmission costs were allocated according to Schedule 12 of PJM's Open Access Transmission Tariff (OATT), where costs are shared across all zones by a combination of load ratio share and distribution factor impacts. The transmission owners include these project costs in their base case, and all retail customers in the PJM footprint pay for those upgrade costs through increased energy bills. The cost allocation of the $1.4 billion in baseline upgrades are assigned to all retail customers and not solely to the customers requesting interconnection.

The high level of customer requests in Data Center Alley resulted in the need for significant baseline reliability upgrades. These costs were allocated per Schedule 12 of the PJM OATT. Not all customer requests result in reliability upgrades. Transmission upgrades for customer requests that are submitted through the supplemental planning process are allocated 100 percent to the zone where they are interconnecting. The transmission owner of that zone then includes those project costs in their rate base, and all retail customers in that zone pay those costs.

The Virginia case illustrates the imposition of transmission costs by data centers on other PJM customers. These additional transmission costs are in addition to the significant capacity market costs imposed on other customers by the actual and forecast addition of large data centers.

The main focus of PJM's planning requirements has been to ensure adequate transmission to allow for generation to reliably serve load. Historically, PJM has had enough excess generation to serve the forecasted load in the RTEP process. In recent years, due in part to the significant increase in load resulting from large load data center interconnection requests and an increase in thermal unit deactivations, meeting forecasted loads and reserves with existing generation has become an

37 OATT Part V §114.

38 See "*Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board*," December 2023. <https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-pjm-teac-board-whitepaper-december-2023.ashx>.

issue. In order to solve the RTEP study cases, PJM must make assumptions about the existing and future generation to include in the RTEP model based on the need to serve load. The RTEP analysis first includes all existing generation that is expected to remain in service for the year being studied. When the forecasted load exceeds the expected in service generation, the RTEP analysis includes future generation. Planned generators with a signed interconnection service agreement (ISA) or generation interconnection agreement (GIA), or that cleared a BRA, are included. When the PJM load in the RTEP analysis exceeds the sum of existing generation and generation with an executed final agreement, the RTEP analysis simply adds speculative new generation that is in its Phase 3 system impact study status to meet the load. If needed, additional generation (pre-GIA stage or with a suspended status) may be modeled (assumed) consistent with the procedures noted in Manual 14B.[39] [40] The RTEP analysis is not adequately coordinated with PJM markets analysis including the energy and capacity markets.

Generation Interconnection Planning

Existing Generation Mix

Table 12-1 shows the existing PJM capacity by control zone and unit type.[41] [42] As of December 31, 2025, PJM had an installed capacity of 202,424.8 MW, of which 38,366.4 MW (19.0 percent) are coal fired steam units, 57,047.4 MW (28.2 percent) are combined cycle units and 33,452.6 MW (16.5 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 installed capacity of any PJM zone. Of the 202,424.8 MW of PJM installed capacity, 37,926.3 MW (18.7 percent) are in the AEP Zone, of which 13,463.0 MW (35.5 percent) are coal fired steam units, 9,294.0 MW (24.5 percent) are combined cycle units and 2,071.0 MW (5.5 percent) are nuclear units.

Table 12-1 Existing capacity: December 31, 2025 (By zone and unit type (MW))[43]

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
ACEC	0.0	781.6	395.5	0.0	0.0	1.6	0.0	0.0	0.0	0.0	4.0	5.4	68.8	0.0	0.0	0.0	0.0	0.0	0.0	7.5	0.0	1,264.3
AEP	0.0	9,294.0	4,028.2	16.2	4.8	0.0	66.0	420.9	2,071.0	0.0	0.0	20.4	4,302.9	0.0	0.0	13,463.0	738.0	0.0	0.0	3,500.9	0.0	37,926.3
AMPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
APS	33.0	2,843.7	1,223.3	0.0	2.0	0.0	0.0	129.2	0.0	22.4	0.0	18.3	611.0	0.0	0.0	5,119.0	0.0	0.0	0.0	1,040.0	0.0	11,041.9
ATSI	0.0	5,571.0	1,383.0	183.0	6.4	0.0	0.0	0.0	2,134.0	0.0	5.5	4.7	757.0	0.0	0.0	0.0	325.0	0.0	136.0	0.0	0.0	10,505.6
BGE	3.5	0.0	267.6	215.9	0.0	0.0	0.0	0.0	1,716.0	0.0	0.0	4.2	31.1	0.0	0.0	1,273.0	17.5	702.0	57.0	0.0	0.0	4,287.8
COMED	104.5	4,631.1	6,753.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	15.0	59.0	0.0	0.0	2,646.0	0.0	0.0	0.0	5,633.2	0.0	30,541.8
DAY	0.0	0.0	897.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	0.0	742.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,674.3
DUKE	12.0	522.2	598.0	56.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	289.9	0.0	0.0	1,252.0	47.0	0.0	0.0	0.0	0.0	2,893.9
DUQ	0.0	306.0	0.0	15.0	0.0	0.0	0.0	6.3	1,777.0	14.4	0.0	0.0	54.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,172.9
DOM	34.7	9,138.0	3,835.3	256.4	10.0	0.0	3,003.0	586.3	3,581.3	0.0	18.0	94.7	5,456.8	0.0	0.0	2,473.2	55.0	0.0	318.4	776.0	0.0	29,637.1
DPL	0.0	1,742.5	978.2	478.2	0.0	30.0	0.0	0.0	0.0	0.0	86.0	14.1	586.0	0.0	0.0	0.0	710.0	153.0	70.0	0.0	0.0	4,848.0
EKPC	0.0	0.0	774.0	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	205.0	0.0	0.0	1,687.0	0.0	0.0	0.0	0.0	0.0	2,802.0
JCPLC	192.8	2,115.5	748.0	0.0	0.0	0.4	140.0	0.0	0.0	0.0	0.0	0.0	477.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,674.5
MEC	0.0	2,595.0	2.0	398.5	0.0	0.0	0.0	19.0	0.0	0.0	0.0	30.9	430.0	0.0	0.0	80.0	35.0	0.0	60.0	0.0	0.0	3,650.4
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	2,388.8	0.0	0.0	0.0	0.0	0.0	2,388.8
PECO	0.0	4,089.0	0.0	828.0	0.0	0.0	1,070.0	572.0	4,546.8	0.0	0.0	0.9	3.0	0.0	0.0	0.0	765.3	0.0	103.0	0.0	0.0	11,978.0
PE	28.4	1,900.0	422.1	57.0	0.0	0.0	513.0	77.8	0.0	120.1	28.0	11.0	326.4	0.0	0.0	4,169.5	610.0	0.0	42.0	1,238.0	0.0	9,543.3
PEPCO	0.0	1,736.5	770.2	258.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.7	35.6	0.0	0.0	0.0	1,164.1	0.0	52.0	0.0	0.0	4,025.1
PPL	20.0	5,558.5	234.0	36.0	20.6	0.0	0.0	706.6	2,520.0	12.0	5.0	14.7	220.0	0.0	0.0	1,859.9	3,137.0	0.0	29.0	216.5	0.0	14,589.8
PSEG	7.7	4,223.1	963.2	0.0	0.0	0.0	0.0	5.0	3,493.0	0.0	0.0	9.0	230.3	0.0	0.0	0.0	3.0	0.0	179.1	0.0	0.0	9,113.3
XIC	0.0	0.0	670.6	0.0	0.0	0.0	0.0	0.0	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	100.0	0.0	3,865.6
Total	436.6	57,047.7	24,944.0	3,024.4	43.8	32.0	4,792.0	2,771.1	33,452.6	168.9	180.5	256.8	14,887.5	0.0	0.0	38,366.4	7,606.9	855.0	1,046.5	12,512.1	0.0	202,424.8

Table 12-2 shows the installed capacity by state for each fuel type. Pennsylvania has the most installed capacity of any PJM state. Of the 202,424.8 MW of installed capacity, 47,504.4 MW (23.5 percent) are in Pennsylvania, of which 6,109.4 MW (12.9 percent) are coal fired steam units, 18,292.2 MW (38.5 percent) are combined cycle units and 8,843.8 MW (18.6 percent) are nuclear units.

39 See "Review of 2025 RTEP Assumptions," presented at the January 7, 2025 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250107/20250107-item-11---2025-rtep-assumption.pdf>.
40 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 58 (December 17, 2025).
41 The unit type RICE refers to Reciprocating Internal Combustion Engines.
42 XIC refers to external installed capacity.
43 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.

Table 12-2 Existing capacity: December 31, 2025 (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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
DC	0.0	19.5	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.5
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	50.0	0.0	0.0	0.0	710.0	0.0	70.0	0.0	0.0	2,052.4
IL	104.5	4,631.1	6,753.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	15.0	59.0	0.0	0.0	2,646.0	0.0	0.0	0.0	5,633.2	0.0	30,541.8
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	1,232.6	0.0	0.0	3,923.8	0.0	0.0	0.0	2,353.2	0.0	9,797.4
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	382.0	0.0	0.0	1,687.0	278.0	0.0	0.0	0.0	0.0	4,101.1
MD	3.5	2,717.0	1,684.5	489.8	0.0	0.0	0.0	0.0	1,716.0	0.0	74.0	18.9	861.9	0.0	0.0	1,273.0	1,181.6	855.0	191.0	349.9	0.0	11,416.1
MI	0.0	994.0	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	0.0	0.0	0.0	3,089.4
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	1,321.5	0.0	0.0	0.0	0.0	0.0	0.0	397.0	0.0	2,216.5
NJ	200.5	7,120.2	2,106.7	0.0	0.0	2.0	140.0	5.0	3,493.0	0.0	4.0	14.4	776.8	0.0	0.0	0.0	3.0	0.0	179.1	7.5	0.0	14,052.1
OH	12.0	11,558.2	4,626.2	255.2	6.4	0.0	0.0	200.0	2,134.0	0.0	34.0	9.5	4,337.4	0.0	0.0	6,820.0	47.0	0.0	136.0	1,147.7	0.0	31,323.6
PA	49.9	18,292.2	1,545.5	1,334.5	20.6	0.0	1,583.0	1,445.7	8,843.8	168.9	38.5	75.8	1,170.4	0.0	0.0	6,109.4	4,872.3	0.0	234.0	1,719.9	0.0	47,504.4
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	0.0	0.0	0.0	0.0	0.0	0.0
VA	34.7	8,973.0	4,092.3	591.4	12.0	0.0	3,069.0	460.1	3,581.3	0.0	12.0	100.7	4,571.3	0.0	0.0	1,468.2	515.0	0.0	236.4	12.0	0.0	27,729.4
WV	31.5	0.0	1,073.9	11.0	0.0	0.0	0.0	189.3	0.0	0.0	0.0	8.0	120.0	0.0	0.0	12,484.0	0.0	0.0	0.0	791.7	0.0	14,709.4
XIC	0.0	0.0	670.6	0.0	0.0	0.0	0.0	0.0	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	100.0	0.0	3,865.6
Total	436.6	57,047.7	24,944.0	3,024.4	43.8	32.0	4,792.0	2,771.1	33,452.6	168.9	180.5	256.8	14,887.5	0.0	0.0	38,366.4	7,606.9	855.0	1,046.5	12,512.1	0.0	202,424.8

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of December 31, 2025. Of the 202,424.8 MW of installed capacity, 75,482.0 MW (37.3 percent) are from units older than 40 years, of which 30,814.3 MW (40.8 percent) are coal fired steam units, 255.0 MW (0.3 percent) are combined cycle units and 25,550.6 MW (33.8 percent) are nuclear units.

Table 12-3 Capacity (MW) by unit type and age (years): December 31, 2025

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Less than 20	436.6	37,816.4	2,404.4	0.0	43.8	32.0	0.0	293.6	0.0	134.5	0.0	150.3	14,887.5	0.0	0.0	2,440.0	82.0	0.0	47.4	12,320.1	0.0	71,088.5
20 to 40	0.0	18,976.3	22,074.8	478.0	0.0	0.0	0.0	193.8	7,902.0	34.4	22.0	90.7	0.0	0.0	0.0	5,112.1	70.0	0.0	708.1	192.0	0.0	55,854.2
40 to 60	0.0	255.0	372.8	2,517.7	0.0	0.0	4,586.0	306.6	25,550.6	0.0	140.5	15.8	0.0	0.0	0.0	27,785.5	5,003.4	855.0	85.0	0.0	0.0	67,473.9
Greater than 60	0.0	0.0	92.0	28.7	0.0	0.0	206.0	1,977.1	0.0	0.0	18.0	0.0	0.0	0.0	0.0	3,028.8	2,451.5	0.0	206.0	0.0	0.0	8,008.1
Total	436.6	57,047.7	24,944.0	3,024.4	43.8	32.0	4,792.0	2,771.1	33,452.6	168.9	180.5	256.8	14,887.5	0.0	0.0	38,366.4	7,606.9	855.0	1,046.5	12,512.1	0.0	202,424.8

Figure 12-1 Capacity (MW) by age (years): December 31, 2025

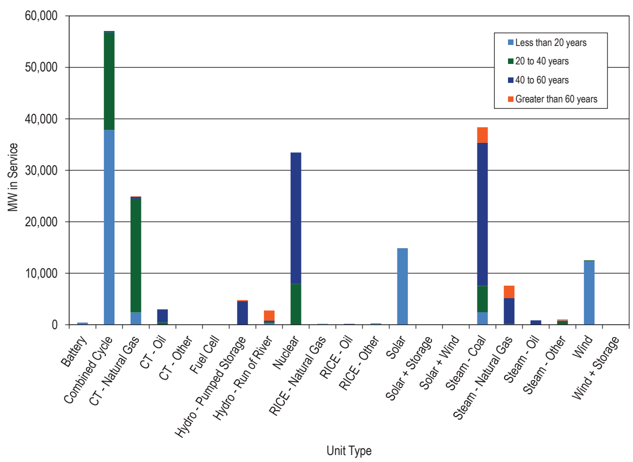


Figure 12-2 is a map of units, less than 20 MW in size that came online between January 1, 2011, and December 31, 2025. A mapping to these unit names is in Table 12-4.

Figure 12-2 Map of unit additions (less than 20 MW): January 1, 2011 through December 31, 2025

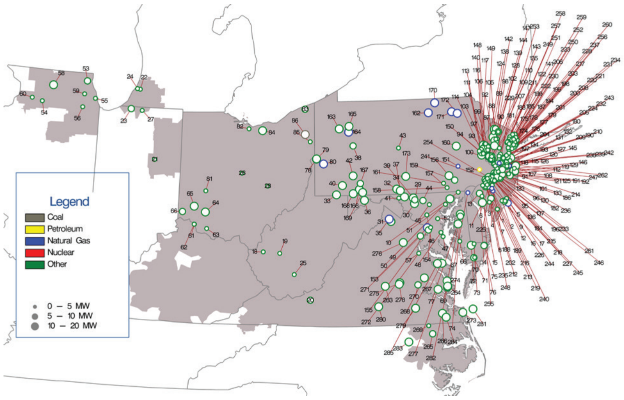


Table 12-4 Unit identification for map of unit additions (less than 20 MW): January 1, 2011 through December 31, 2025

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CAPE MAY COUNTY 1 LF	56	COM MAGID GLOVE 1 BT	111	JC FRENCHTOWN 3 SP	166	PN GARRETT 1 BT	221	PS MATRIX PA SOLAR 2 SP	276	VP REMINGTON 1 SP
2	ACE CATES ROAD 2 SP	57	COM MORRIS 1 LF	112	JC HANOVER 2 SP	167	PN LAUREL HIGHLANDS 2 LF	222	PS MAYWOOD SOLAR 1 SP	277	VP ROCHAMBEAU 1 SP
3	ACE CEDAR BRANCH 1 SP	58	COM ORCHARD 1 LF	113	JC HARMONY 1 SP	168	PN LISTONBURG 1 SP	223	PS METRO HQ 2 SP	278	VP SCOTT - POWHATAN 3 HB
4	ACE EGG HARBOR-KELLOGG 1 FC	59	COM SOLBERG 1 BT	114	JC HIGH STREET 6 SP	169	PN MEYERSDALE 2 BT	224	PS MIDDLESEX 1 SP	279	VP SHANDS ENERGY 2 BT
5	ACE GALLOWAY LANDFILL 2 SP	60	COM STERLING RAIL 1 BT	115	JC HOFFMAN STATION ROAD 2 SP	170	PN MILAN ENERGY 1 D	225	PS MILL CREEK 1 SP	280	VP TWITTYS CREEK 1 SP
6	ACE GEMS LANDFILL 1 SP	61	DEOK BECKJORD 1 BT	116	JC HOLLAND 4 SP	171	PN NORTH MESHOPPEN 1 CT	226	PS MOORESTOWN 1 SP	281	VP VIRGINIA OFFSHORE 1 WF
7	ACE KETTLE RUN 1 SP	62	DEOK BECKJORD 2 BT	117	JC HOLLAND-MORRISPA 8 SP	172	PN OXBOW CREEK ENERGY CENTER 1 D	227	PS MT LAUREL 1 SP	282	VP WAN - GLOUCESTER 1 SP
8	ACE MAYS LANDING 1 SP	63	DEOK BROWN COUNTY 1 LF	118	JC HOLMDEL 9 SP	173	PN WHITETAIL 1 SP	228	PS NEW MILFORD SOLAR 1 SP	283	VP WHITAKERS 1 SP
9	ACE MIDTOWN THERMAL 2 CT	64	DEOK CLINTON 1 BT	119	JC HOWELL 1 SP	174	PS ALDENE SOLAR 1 SP	229	PS NEW ROAD 1 SP	284	VP WHITE MARSH - SUFFOLK 1 SP
10	ACE MONROE - SICKLERVILLE 1 SP	65	DEOK NICKEL - CIN ZOO 1 SP	120	JC HOWELL 4 BT	175	PS ATHENIA SOLAR 1 SP	230	PS NEWARK SOLAR 1 SP	285	VP WOODBINE ROAD 1 SP
11	ACE OAK FAIRTON 1 SP	66	DEOK WILLEY 1 BT	121	JC JACOBSTOWN 1 SP	176	PS BAYONNE 1 SP	231	PS NEWARK SOLAR 3 SP		
12	ACE PEAR STREET 1 SP	67	DPL BLOOM ENERGY 1 FC	122	JC JUNCTION ROAD 6 SP	177	PS BAYONNE SOLAR 2 SP	232	PS NIXON LANE 2 SP		
13	ACE PILESGROVE 1 SP	68	DPL BUCKTOWN 1 SP	123	JC LAKEHURST 3 SP	178	PS BELLEVILLE SOLAR 1 SP	233	PS NORTH AMERICAN 4 SP		
14	ACE PILESGROVE 2 SP	69	DPL CHURCH HILL 1 SP	124	JC LEBANON 1 SP	179	PS BENNETTS SOLAR 1 SP	234	PS NORTH AVE SOLAR 1 SP		
15	ACE PITTSGROVE 1 SP	70	DPL COSTEN 1 SP	125	JC LEGLER LANDFILL 7 SP	180	PS BLACK ROCK 1 SP	235	PS OWENS CORNING 1 SP		
16	ACE SEASHORE 1 SP	71	DPL COSTEN 2 SP	126	JC MANALAPAN 1 SP	181	PS BRIDGEWATER SOLAR 2 SP	236	PS PARKLANDS 1 SP		
17	ACE TANSBORO ROAD 1 FC	72	DPL HEBRON 1 SP	127	JC MILLHURST 3 SP	182	PS BUSTLETON 2 SP	237	PS PATERSON PLANK ROAD 1 SP		
18	AEP BALLS GAP 1 BT	73	DPL KUMQUAT 1 SP	128	JC MOUNT OLIVE 3 SP	183	PS CALDWELL PUMP 2 BT	238	PS PENNINGTON 3 BT		
19	AEP CHARLESTON 1 LF	74	DPL PONDTOWN 1 SP	129	JC MUDDY FORGE 3 SP	184	PS CAMPUS DRIVE 2 SP	239	PS PENNINGTON 4 SP		
20	AEP CLOYDS MT 1 LF	75	DPL WORCESTER NORTH 1 SP	130	JC NORTH HANOVER 4 SP	185	PS CEDAR GROVE SOLAR 1 SP	240	PS PENNSAUKEN 1 LF		
21	AEP DEERCREEK 1 SP	76	DPL WORCESTER SOUTH 2 SP	131	JC NORTH PARK 1 SP	186	PS CEDAR LANE FLORENCE 6 SP	241	PS PENNSAUKEN 3 SP		
22	AEP EAST WATERVLIET 1 SP	77	DPL WYE MILLS 1 SP	132	JC NORTH PARK 2 SP	187	PS COOK ROAD SOLAR 2 SP	242	PS PRINCETON HOSPITAL 1 CT		
23	AEP OLIVE 1 SP	78	DUQ BE-PINE 1 SP	133	JC NORTH RUN 11 SP	188	PS COOPER HOSPITAL 1 BT	243	PS RARITAN CENTER 3 SP		
24	AEP ORCHARD HILLS 1 LF	79	DUQ BE-PINE 2 SP	134	JC OLD BRIDGE 1 SP	189	PS COOPER HOSPITAL 15 SP	244	PS REEVES EAST 3 SP		
25	AEP RALEIGH COUNTY 1 LF	80	DUQ PIT MICROGRID 1 CT	135	JC PAUCH 3 SP	190	PS CRANBURY 2 SP	245	PS REEVES SOUTH 1 SP		
26	AEP TRENT 1 BT	81	FE DOVETAIL 1 CT	136	JC PEMBERTON 1 SP	191	PS CROSSWIC 1 SP	246	PS REEVES WEST 4 SP		
27	AEP TWINBRANCH 1 SP	82	FE ERIE COUNTY 1 LF	137	JC PEMBERTON 2 SP	192	PS CROSSWIC 2 SP	247	PS RIDER UNIVERSITY 3 SP		
28	AEP ZANESVILLE 2 LF	83	FE GENEVA 1 LF	138	JC QUAKERTOWN 12 SP	193	PS DEVILSBROOK 1 SP	248	PS RIVER ROAD 2 SP		
29	AP BAKER POINT 1 SP	84	FE LORAIN 1 LF	139	JC QUAKERTOWN 9 SP	194	PS DOREMUS SOLAR 1 SP	249	PS ROSELAND SOLAR 1 SP		
30	AP BIGGS FORD 1 SP	85	FE MAHONING 1 LF	140	JC RICHLINE 3 SP	195	PS E RUTHERFORD SOLAR 1 SP	250	PS RUTGERS GENERATION 1 F		
31	AP DOUBLE TOLLGATE SP	86	FE WARREN-EVERGREEN 1 CT	141	JC RINGOES 1 SP	196	PS EASTAMPTON 1 SP	251	PS SADDLE BROOK SOLAR 1 SP		
32	AP ELK HILL 1 SP	87	JC AUGUSTA 1 SP	142	JC ROY ROAD 5 BT	197	PS EDISON 1 SP	252	PS SPRINGFIELD SOLAR 1 SP		
33	AP GANS 5 SP	88	JC BEAVER RUN 3 SP	143	JC SOUTH COMBE 2 SP	198	PS ESSEX 105 CT	253	PS SUNNYMEADE SOLAR 1 SP		
34	AP HAGERSTOWN 1 SP	89	JC BERKSHIRE 2 SP	144	JC SUSSEX 1 LF	199	PS FAIRLAWN SOLAR 1 SP	254	PS TAYLORS LANE 1 SP		
35	AP HP HOOD 1 CT	90	JC BERNARDS TOWNSHIP 1 SP	145	JC TINTON FALLS 3 SP	200	PS FOODBANK 1 SP	255	PS THOROFARE SOLAR 2 SP		
36	AP JADE MEADOW 1 SP	91	JC BRICKYARD 4 SP	146	JC UPPER FREEHOLD 1 SP	201	PS FORTY NINTH SOLAR 1 SP	256	PS TURNPIKE 1 SP		
37	AP LETZBURG - ELK HILL 2 SP	92	JC BRIGHT ROAD 2 BT	147	JC WANTAGE 2 SP	202	PS GLOUCESTER SOLAR 1 SP	257	PS W CALDWELL SOLAR 1 SP		
38	AP MAHONING CREEK 1 H	93	JC COPPER HILL 4 SP	148	JC WARREN 1 SP	203	PS HACKENSACK 1 SP	258	PS W CALDWELL SOLAR 2 SP		
39	AP MT ST MARYS PV PARK 2 SP	94	JC CYPHERS ROAD 5 SP	149	JC WASHBURN AVE 4 SP	204	PS HIGHLAND PARK 3 BT	259	PS WALDWICK SOLAR 1 SP		
40	AP PECHIN 2 SP	95	JC DIXSOLAR 51 SP	150	ME GLENDON 1 LF	205	PS HIGHLAND PARK 4 SP	260	PS WEST ORANGE SOLAR 1 SP		
41	AP PINESBURG 1 SP	96	JC DIXSOLAR 52 SP	151	ME READING HOSPITAL 1 CT	206	PS HILLSDALE SOLAR 1 SP	261	PS WEST PEMBERTON 1 SP		
42	AP SPRING LANE 1 SP	97	JC DOMIN LANE 1 SP	152	PE MORRIS ROAD 1 D	207	PS HINCHMANS SOLAR 1 SP	262	PS WEST WINDSOR 1 CT		
43	AP STATE COLLEGE 1 BT	98	JC DURBAN AVENUE 1 SP	153	PEP CAPITAL POWER PLANT 1 CT	208	PS HOBOKEN SOLAR 2 SP	263	VP BUCKINGHAM 1 SP		
44	AP UNION BRIDGE 1 SP	99	JC E FLEMINGTON 5 SP	154	PEP ROLLINS AVENUE 3 SP	209	PS HOPEWELL 1 SP	264	VP CAMELLIA - WAN 2 SP		
45	BC ALPHA RIDGE 1 LF	100	JC EAST AMWELL 7 SP	155	PEP SPECTRUM 1 SP	210	PS HOPEWELL 2 BT	265	VP COLICE HALL 1 SP		
46	BC BRIGHTON DAM 1 H	101	JC EGYPT 3 SP	156	PL DART CONTAINER 1-2 LF	211	PS JACKSON SOLAR 1 SP	266	VP GARDNER FARMS 1 SP		
47	BC CHESAPEAKE BEACH 1 BT	102	JC FISCHER 8 SP	157	PL HOLTWOOD 11	212	PS KINSLEY BEAVER 2 SP	267	VP GARDYS MILL ROAD 5 SP		
48	BC FAIRHAVEN 2 BT	103	JC FOUL RIFT 8 SP	158	PL HOLTWOOD 13	213	PS KINSLEY DEPTFORD 1 SP	268	VP HOLLYFIELD 1 SP		
49	BC FAIRVIEW - OTTERPT 1SP	104	JC FOUL RIFT ROAD 1 SP	159	PL KEYSTONE 1 SP	214	PS KUSER SOLAR 1 SP	269	VP MURPHY 1 SP		
50	BC FAIRVIEW - OTTERPT 2SP	105	JC FRANKFORD 4 SP	160	PL PA SOLAR 1 SP	215	PS LANDFILL 5 SP	270	VP NORTHEAST 2 LF		
51	BC KINGSVILLE 1 SP	106	JC FRANKLIN 7 SP	161	PL TURKEY HILL 1 WF	216	PS LAWNSIDE 14 BT	271	VP OCCOQUAN 1 LF		
52	BC MILLERSVILLE 1 LF	107	JC FREEMALL 1 FC	162	PN ALPACA GLORY BARN 1 D	217	PS LEONIA SOLAR 1 SP	272	VP OCCOQUAN 2 LF		
53	COM COUNTRYSIDE 1 LF	108	JC FRENCHES 2 SP	163	PN CARDINAL - CLARKSUM 1 SP	218	PS LUMBERTON STACY HAINES 5 SP	273	VP OCEANA 1 SP		
54	COM DIXON LEE 5 LF	109	JC FRENCHTOWN 1 SP	164	PN CLARION BOARDS 2 CT	219	PS MANTUA CREEK 7 BT	274	VP PULLER 1 SP		
55	COM GRAND RIDGE 6 BT	110	JC FRENCHTOWN 2 SP	165	PN COBALT 1 SP	220	PS MARION SOLAR 1 SP	275	VP QUILLWORT 4 SP		

Figure 12-3 is a map of units, 20 MW or greater in size, that came online between January 1, 2011 and December 31, 2025. A mapping to these unit names is in Table 12-5.

Figure 12-3 Map of unit additions (20 MW or greater): January 1, 2011 through December 31, 2025

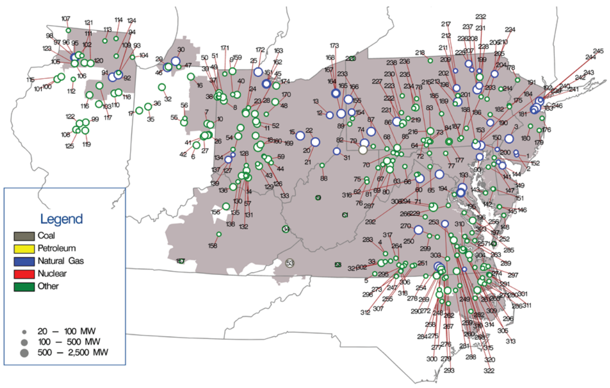


Table 12-5 Unit identification for map of unit additions (20 MW or greater): January 1, 2011 through December 31, 2025

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CLAYVILLE 1 CT	56	AEP WILDCAT 1B WF	111	COM LEE DEKALB 3 BT	166	FE HICKORY RUN 1 CC	221	PN FAIRVIEW 1 CC	276	VP GUTENBERG - OCONECHE 1 SP
2	ACE VINELAND 11 CT	57	AEP WILLOWBROOK 1 SP	112	COM LONE TREE 3 WF	167	FE LORDSTOWN ENERGY CENTER 1 CC	222	PN FAIRVIEW 2 CC	277	VP HARTS MILL 1 SP
3	ACE WEST DEPTFORD CROWN POINT 1 CC	58	AEP WYTHE COUNTY 1 SP	113	COM MARENGO 1 BT	168	FE LORDSTOWN ENERGY CENTER 2 CC	223	PN HIGHLAND NORTH 2 WF	278	VP HAWTREE CREEK 1 SP
4	AEP ALTAVISTA 1 SP	59	AEP YELLOWBUD 1 SP	114	COM MCHENRY 1 BT	169	FE MADISON FIELDS 1 SP	224	PN LAUREL HILLS 1 WF	279	VP IVORY LANE 1 SP
5	AEP AXTON 1 SP	60	AP BARTONSVILLE 1 SP	115	COM MIDLAND 1 WF	170	FE MARION COUNTY 1 SP	225	PN LIBERTY ASYLUM 10 F	280	VP IVY NECK 2 SP
6	AEP BELLFLOWER 1 SP	61	AP BEECH RIDGE 2 WF	116	COM MINONK 1 WF	171	FE MONTPELIER 1 SP	226	PN LIBERTY ASYLUM 20 F	281	VP KELFORD 1 SP
7	AEP BITTER RIDGE 1 WF	62	AP BEECH RIDGE 3 BT	117	COM OTTER CREEK 1 WF	172	FE OREGON ENERGY CENTER 1 CC	227	PN MAPLE HILL-FIDDLERS 1 SP	282	VP MACKEYS ALBERMAE 1 SP
8	AEP BLUE CREEK 3 WF	63	AP BLACK ROCK 1 WF	118	COM PILOT HILL 1 WF	173	FE TRUMBULL EC 1 CC	228	PN MEHOOPANY 1 WF	283	VP MECHANICSVILLE 2 SP
9	AEP BLUE HARVEST 1 SP	64	AP BLAIRS VALLEY 12 SP	119	COM RADFORDS RUN 1 WF	174	FE WHEATSBOROUGH 1 SP	229	PN MEHOOPANY 2 WF	284	VP MOCCASIN CREEK - FERN 1 SP
10	AEP BLUFF POINT 2 WF	65	AP BLAKE 1 SP	120	COM SHADY OAKS 1 WF	175	JC EDGE ROAD 5 BT	230	PN PATTON 1 WF	285	VP MONTROSS 1 SP
11	AEP CADENCE 1 SP	66	AP CAPON BRIDGE 1 SP	121	COM SHADY OAKS 2 WF	176	JC HAMILTON ROAD 5 SP	231	PN PGCOGEN 1 CT	286	VP MORGAN CORNER 1 SP
12	AEP CARROLL COUNTY 1 CC	67	AP CPV BACKBONE 1 SP	122	COM TOP HAT 1 WF	177	JC JUSTIN COURT 10 BT	232	PN PGCOGEN 2 CT	287	VP NEW CREEK 1 WF
13	AEP CARROLL COUNTY 2 CC	68	AP DANS MOUNTAIN 1 WF	123	COM WALNUT RIDGE 1 WF	178	JC MONTAGUE STORAGE 3 BT	233	PN RINGER HILL 1 WF	288	VP NEWSOMS 1 SP
14	AEP DODSON CREEK 1 SP	69	AP FAIR WIND 2 WF	124	COM WEST CHICAGO 3 BT	179	JC OAK RIDGE 3 SP	234	PN SANDY RIDGE 1 WF	289	VP NORGE 2 SP
15	AEP DRESDEN 1 CC	70	AP FOURMILE RIDGE 1 WF	125	COM WHITNEY HILL 2 WF	180	JC PLUMSTED ENERGY 6 BT	235	PN SANDY RIDGE 2 WF	290	VP OAK 1 SP
16	AEP ELKHART COUNTY - MCNUTT 1 SP	71	AP FOXGLOVE 1 SP	126	DAY BUCKEYE PLAINS 2 SP	181	JC SAYREVILLE 3 CT	236	PN SCHOOL HOUSE 1 SP	291	VP OAK TRAIL 1 SP
17	AEP FOWLER RIDGE 4 WF	72	AP GREAT COVE 1 SP	127	DAY CLEARVIEW 1 SP	182	JC WARREN GLEN 6 BT	237	PN SUGAR RUN 2 CT	292	VP PANDA STONEWALL 1 CC
18	AEP FOX SQUIRREL 1 SP	73	AP GREAT COVE 2 SP	128	DAY CLINTON - EASTFORK 1 SP	183	JC WOODBRIDGE 1 CC	238	PN VIADUCT 1 SP	293	VP PECAN 1 SP
19	AEP GREAT BEND 1 SP	74	AP GREENE COUNTY 1 CC	129	DAY FAYETTE 1 SP	184	JC WOODBRIDGE 2 CC	239	PS KEARNY 131 CT	294	VP PINE GLADE 1 SP
20	AEP GUERNSEY 11 CC	75	AP LAUREL MOUNTAIN 1 BT	130	DAY HIGHLAND COUNTY 1 SP	185	ME ADAMS 1 SP	240	PS KEARNY 132 CT	295	VP PINEY CREEK 1 SP
21	AEP GUERNSEY 21 CC	76	AP LAUREL MOUNTAIN 1 WF	131	DAY HIGHLAND COUNTY 2 SP	186	ME BIRDSBORO 1 CC	241	PS KEARNY 133 CT	296	VP PLEASANT HILL - SUFFOLK 2 SP
22	AEP GUERNSEY 31 CC	77	AP LEGORE BRIDGE 1 SP	132	DAY HIGHLAND COUNTY 3-4 SP	187	ME COTTONTAIL 1 SP	242	PS KEARNY 134 CT	297	VP POCATY 1 SP
23	AEP HARDIN 12 SP	78	AP MARLOWE 1 SP	133	DAY PICKAWAY COUNTY 1 SP	188	ME COTTONTAIL 2 SP	243	PS KEARNY 141 CT	298	VP POWELLS CREEK 1 SP
24	AEP HARDIN 23 SP	79	AP NORTH LONGVIEW 1 F	134	DAY TAIT 8 BT	189	ME COTTONTAIL 8 SP	244	PS KEARNY 142 CT	299	VP POWHATAN 2 SP
25	AEP HARDIN 34 SP	80	AP PINNACLE 1 WF	135	DEOK HILLCREST 1 SP	190	ME LYONS 1 SP	245	PS NEWARK ENERGY CENTER 10 CC	300	VP PUMPKINSEED 1 SP
26	AEP HEADWATERS 1 WF	81	AP ROTH ROCK 1 WF	136	DEOK MELDAHL DAM 1 H	191	PE DELTA 1-4 CC	246	PS SEWAREN 7 CC	301	VP RANCHLAND 2 SP
27	AEP HEADWATERS 2 WF	82	AP SOUTH CHESTNUT 1 WF	137	DEOK MIDDLETOWN ENERGY 1 CC	192	PE DELTA 5-7 CC	247	VP ALTON POST OFFICE 1 SP	302	VP RENAN 1 SP
28	AEP HOG CREEK 1 WF	83	AP ST THOMAS 1 SP	138	DEOK NESTLEWOOD 1 SP	193	PEP KEYS ENERGY CENTER 1 CC	248	VP AMERICAN BEECH 1 SP	303	VP SAPONY 1 SP
29	AEP HONEYSUCKLE 1 SP	84	AP ST THOMAS 2 SP	139	DEOK YANKEE 1 F	194	PEP MILLS GROVE 1 SP	249	VP AULANDER HOLLOMAN 1 SP	304	VP SHILLELAGH 1 SP
30	AEP INDECK NILES ENERGY CENTER 1 CC	85	AP TWIN RIDGES 1 WF	140	DPL CHERRYDALE 1 SP	195	PEP ST CHARLES - KELSON RIDGE 1 CC	250	VP BEAR GARDEN	305	VP SOLIDAGO 1 SP
31	AEP LONG RIDGE ENERGY 1 CC	86	AP WARRIOR RUN 2 BT	141	DPL DEMEC - CLAYTON 2 CT	196	PEP ST CHARLES-KELSON RIDGE 1 CC	251	VP BLUESTONE FARM 1 SP	306	VP SOUTH BOSTON 1 F
32	AEP MAMMOTH NORTH 1 SP	87	AP WESTMORELAND 1 CC	142	DPL DORCHESTER COUNTY 1 SP	197	PEP ST CHARLES-KELSON RIDGE 2 CC	252	VP BOOKERS MILL 1 SP	307	VP SPANISH GROVE 1 SP
33	AEP MAPLEWOOD 1 SP	88	AP WILLOW ISLAND 1 H	143	DPL EGYPT ROAD - MACELANE 1 SP	198	PL EAST CHILLI 1 SP	253	VP BRIEL FARM 1 SP	308	VP SPOTSYLVANIA 1 SP
34	AEP MARTIN COUNTY 1 SP	89	AP WS SARISH - SMITH FRANCIS 1 SP	144	DPL GARRISON EC 1 CC	199	PL HAZEL 1 FW	254	VP BRUNSWICK 1CC	309	VP SPRING GROVE 1 SP
35	AEP MEADOW LAKE 5 WF	90	BC PERRYMAN 6 CT	145	DPL GREAT BAY KINGS CREEK 1 SP	200	PL HOLTWOOD 18	255	VP BUTCHER CREEK 1 SP	310	VP SPRING GROVE 2 SP
36	AEP MEADOW LAKE 6 WF	91	COM 924 THREE RIVERS EC 1 CC	146	DPL GREAT BAY KINGS CREEK 2 SP	201	PL HOLTWOOD 19	256	VP CARVERS CREEK 1 SP	311	VP SUMMIT FARMS 1 SP
37	AEP PAULDING 3 WF	92	COM 924 THREE RIVERS EC 2 CC	147	DPL JONES FARM LANE 1 SP	202	PL HUMMEL STATION 1 CC	257	VP CAVALIER 1 SP	312	VP SUNNYBROOK FARM 1 SP
38	AEP PAULDING 41 WF	93	COM 929 JACKSON 1 CC	148	DPL OAK HALL 1 SP	203	PL HUNLOCK CC	258	VP CHESTNUT 1 SP	313	VP TIMBERMILL 1 WF
39	AEP PAULDING 42 WF	94	COM 929 JACKSON 2 CC	149	DPL PONDTOWN 2 SP	204	PL LACKAWANNA COUNTY 1 CC	259	VP CHICKAHOMINY 1 SP	314	VP UNION CAMP 9-10 F
40	AEP POWELL CREEK - LAMMER 1 SP	95	COM 942 NELSON 1 CC	150	DPL RED LION 1 FC	205	PL LACKAWANNA COUNTY 2 CC	260	VP CHICKAHOMINY 2 SP	315	VP WARDS CREEK 1 SP
41	AEP RIVERSTART 1 SP	96	COM 942 NELSON 2 CC	151	DPL RICHFIELD 3 SP	206	PL LACKAWANNA COUNTY 3 CC	261	VP COLONIAL TRAIL WEST 1 SP	316	VP WARREN COUNTY FRONT ROYAL CC
42	AEP RIVERSTART 3 SP	97	COM 942 NELSON 3 CT	152	DPL TOWNSEND 1 SP	207	PL MOXIE FREEDOM 11 CC	262	VP CONETOE 2 SP	317	VP WATER STRIDER 1 SP
43	AEP ROSS COUNTY 1 SP	98	COM 942 NELSON 4 CT	153	DPL WILDCAT POINT 1 CC	208	PL MOXIE FREEDOM 21 CC	263	VP CORRECTIONAL 1 SP	318	VP WATLINGTON 1 SP
44	AEP SALT CITY 1 SP	99	COM ALTA FARMS II 1 WF	154	DUQ GAUCHO 2 SP	209	PL NORTHUMBERLAND 2 SP	264	VP CRYSTAL HILL 1 SP	319	VP WAVERLY 1 SP
45	AEP SCIOTO RIDGE 1 WF	100	COM BISHOP HILL 1 WF	155	DUQ MONACA-PENNCHEM 1 CC	210	PL PA SOLAR 2 SP	265	VP DESERT 1 WF	320	VP WAVERLY 2 SP
46	AEP ST JOSEPH ENERGY CENTER 1 CC	101	COM BISHOP HILL 2 WF	156	EKPC BLUEBIRD 1 SP	211	PL PATRIOT 1 F	266	VP DESPER 1 SP	321	VP WHITEHORN 1 SP
47	AEP ST JOSEPH SOLAR PARK 1 SP	102	COM BLOOMING GROVE 1 WF1	157	EKPC GLOVER CREEK 1 SP	212	PL PATRIOT 2 F	267	VP DOSWELL 2 CT	322	VP WILKINSON ENERGY CENTER 1 SP
48	AEP SYCAMORE CREEK 1 SP	103	COM BRIGHT STALK 1 WF	158	EKPC TURKEY CREEK 1 SP	213	PL PENN 3 SP	268	VP DOSWELL 3 CT	323	VP WINTERBERRY 1 SP
49	AEP TIMBER ROAD 1 SP	104	COM GRAND RIDGE 7 BT	159	FE ARCHE ENERGY 1 SP	214	PL SWIFTWATER 1 SP	269	VP DRY BREAD 1 SP		
50	AEP TIMBER2 1 WF	105	COM GREEN RIVER 1 WF	160	FE BIG PLAIN 2 SP	215	PL WALKER 1 SP	270	VP DRY BRIDGE EC 1 BT		
51	AEP TRISHE 1 WF	106	COM GREEN RIVER 2 WF	161	FE FREMONT 1 SCCT	216	PN ASPEN ROAD 1 SP	271	VP ELIZABETH CITY 1 SP		
52	AEP UNION 1 SP	107	COM HIGHPOINT 11 SP	162	FE FREMONT 2 SCCT	217	PN BEAVER DAM 1 D	272	VP FOUNTAIN CREEK 1 SP		
53	AEP VIRGINIA CITY 1 F	108	COM HILLTOPPER 1 WF	163	FE FREMONT ENERGY CENTER 3 CC	218	PN BIG LEVEL 1 WF	273	VP FOXHOUND 1 SP		
54	AEP WAPAHANI - RIVERSTART IV 1 SP	109	COM JOLIET 1 BT	164	FE HIBBETS MILL SOUTHFIELD 1 CC	219	PN CHESTNUT FLATS 1 WF	274	VP GRASSFIELD 1 SP		
55	AEP WILDCAT 1A WF	110	COM KELLY CREEK 1 WF	165	FE HIBBETS MILL SOUTHFIELD 2 CC	220	PN ERIE 1 SP	275	VP GREENSVILLE 1 CC		

Generation Retirements[44] [45] [46]

Generating units generally plan to retire when they are not economic and do not expect to be economic. Generating units may also plan to retire if environmental restrictions make it too costly to comply or impossible to comply. 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.[47] 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. The U. S. Department of Energy does have the authority to temporarily order generating plants to continue operating under section 202(c) of the Federal Power Act in the event of emergency or reliability issues.[48]

Rules that preserve ownership of 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 that period can be further extended, at no cost, if the CIRs are assigned to a new project in the interconnection queue at the same point of interconnection.[49] 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 that terminate CIRs on the date of retirement, would make new entry appropriately more attractive. There is no good economic and policy rationale for extending ownership rights to CIRs for inactive units. Incumbent providers receive a significant advantage simply by imposing on new entrants the entire cost of system upgrades needed to accommodate new entrants. 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.[50] The MMU recognized the progress made in this rule change, but it did not fully address the issues. 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 or to exercise market power by requiring high payments for CIRs. The MMU recommends that CIRs should end on the date of retirement in order to help ensure competitive markets and competitive access to the grid.

Generation Retirements 2011 through 2030

Table 12-6 shows that as of December 31, 2025, there were 64,081.0 MW of generation that have been, or are planned to be, retired from 2011 through 2030, of which 46,526.8 MW (72.6 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.

44 See PJM. Planning. "Generator Deactivations," (Accessed on December 31, 2025) <https://www.pjm.com/planning/service-requests/gen-deactivations>.
45 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.
46 For additional information on canceled unit retirement requests, see *2025 Annual State of the Market Report for PJM*: Volume 2, Section 5: Capacity, "Timing of Unit Retirements".
47 See OATT Part V and Attachment M–Appendix § IV.
48 See 16 U.S.C. § 824a(c).
49 See OATT § 230.3.3.
50 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).

Table 12-6 Summary of unit retirements by unit type (MW): 2011 through 2030

	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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	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	0.0	0.0	543.0	522.5	0.0	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	0.0	0.0	5,907.9	0.0	548.0	16.0	0.0	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	0.0	0.0	2,589.9	82.0	166.0	8.0	0.0	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	0.0	0.0	2,239.0	158.0	0.0	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	0.0	0.0	7,064.8	0.0	0.0	0.0	10.4	0.0	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	0.0	0.0	243.0	74.0	0.0	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	0.0	0.0	2,038.0	34.0	0.0	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	0.0	0.0	3,166.5	1,016.0	148.0	108.0	0.0	0.0	5,542.7
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	0.0	0.0	4,110.5	100.3	10.0	10.0	0.0	0.0	5,456.3
Retirements 2020	0.0	0.0	232.5	24.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	14.7	0.0	0.0	0.0	2,131.8	0.0	786.0	60.0	0.0	0.0	3,255.0
Retirements 2021	4.0	118.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.9	0.0	0.0	0.0	1,020.4	102.0	0.0	50.0	0.0	0.0	1,310.3
Retirements 2022	41.0	240.5	99.0	360.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.6	0.0	0.0	0.0	5,385.0	0.0	0.0	0.0	0.0	0.0	6,162.4
Retirements 2023	0.0	114.0	52.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.0	19.2	0.0	0.0	0.0	4,380.0	1,326.0	800.0	0.0	0.0	0.0	6,727.8
Retirements 2024	28.5	0.0	149.2	108.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.7	0.0	0.0	0.0	180.0	0.0	0.0	50.0	0.0	0.0	527.4
Retirements 2025	33.4	16.5	380.0	12.9	0.0	0.0	0.0	0.0	0.0	0.0	4.0	15.0	2.5	0.0	0.0	410.0	126.0	0.0	0.0	0.0	0.0	1,000.3
Planned Retirements (January 1, 2026 and later)	0.0	0.0	1,740.0	16.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,117.0	760.0	702.0	0.0	0.0	0.0	8,335.4
Total	147.9	914.0	4,705.1	2,322.5	22.0	0.0	0.5	0.0	1,419.5	0.0	84.1	162.9	2.5	0.0	0.0	46,526.8	4,300.8	3,160.0	302.0	10.4	0.0	64,081.0

Table 12-7 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2030, while Table 12-8 shows these retirements by state. Of the 64,081.0 MW of units that has been, or are planned to be, retired from 2011 through 2030, 46,526.8 MW (72.6 percent) are coal fired steam units. These coal fired steam units have an average age of 52.2 years and an average size of 238.6 MW. Over half of the retiring coal fired steam units, 51.1 percent, are located in Ohio or Pennsylvania.

Table 12-7 Retirements by unit type: 2011 through 2030

Unit Type	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Battery	12	12.3	8.2	147.9	0.2%
Combined Cycle	8	114.3	27.0	914.0	1.4%
Combustion Turbine	159	31.1	35.2	7,049.6	11.0%
Natural Gas	84	56.0	39.5	4,705.1	7.3%
Oil	69	33.7	47.0	2,322.5	3.6%
Other	6	3.7	19.2	22.0	0.0%
Fuel Cell	0	0.0	0.0	0.0	0.0%
Hydro	1	0.5	113.8	0.5	0.0%
Pumped Storage	1	0.5	113.8	0.5	0.0%
Run of River	0	0.0	0.0	0.0	0.0%
Nuclear	2	709.8	47.2	1,419.5	2.2%
RICE	47	5.2	26.8	247.0	0.4%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	18	4.7	40.3	84.1	0.1%
Other	29	5.6	13.2	162.9	0.3%
Solar	0	0.0	0.0	0.0	0.0%
Solar + Storage	0	0.0	0.0	0.0	0.0%
Solar + Wind	0	0.0	0.0	0.0	0.0%
Steam	239	197.2	46.1	54,289.6	84.7%
Coal	195	238.6	52.2	46,526.8	72.6%
Natural Gas	26	165.4	57.9	4,300.8	6.7%
Oil	9	351.1	49.1	3,160.0	4.9%
Other	9	33.6	25.3	302.0	0.5%
Wind	1	10.4	15.6	10.4	0.0%
Wind + Storage	0	0.0	0.0	0.0	0.0%
Total	470	136.3	44.0	64,081.0	100.0%

Table 12-8 Retirements (MW) by unit type and state: 2011 through 2030

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	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	0.0	0.0	548.0	0.0	0.0	0.0	788.0
DE	0.0	0.0	0.0	16.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	664.0	136.0	0.0	0.0	0.0	0.0	816.4
IL	45.5	0.0	2,095.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.7	0.0	0.0	0.0	3,926.1	1,326.0	0.0	0.0	0.0	0.0	7,429.2
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	0.0	0.0	3,602.0	0.0	0.0	0.0	0.0	0.0	3,602.0
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	0.0	0.0	1,111.0	0.0	0.0	0.0	0.0	0.0	1,111.0
MD	20.0	0.0	347.5	274.9	1.6	0.0	0.0	0.0	0.0	0.0	2.0	3.2	0.0	0.0	0.0	4,521.0	297.0	702.0	0.0	0.0	0.0	6,169.2
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	0.0	0.0	324.5	0.0	0.0	0.0	0.0	0.0	355.5
NJ	0.0	579.5	2,060.3	1,066.2	6.4	0.0	0.5	0.0	614.5	0.0	8.0	36.6	2.5	0.0	0.0	2,001.9	932.5	148.0	10.0	0.0	0.0	7,466.9
OH	52.0	16.5	0.0	307.0	0.0	0.0	0.0	0.0	0.0	0.0	34.3	46.7	0.0	0.0	0.0	16,607.4	0.0	0.0	0.0	0.0	0.0	17,063.9
PA	1.0	51.0	121.4	307.3	14.0	0.0	0.0	0.0	805.0	0.0	15.9	20.5	0.0	0.0	0.0	7,180.0	1,046.3	176.0	109.0	10.4	0.0	9,857.8
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	0.0	0.0	50.0	0.0	0.0	50.0
VA	0.0	267.0	80.0	79.7	0.0	0.0	0.0	0.0	0.0	0.0	23.9	20.1	0.0	0.0	0.0	3,897.9	563.0	1,586.0	133.0	0.0	0.0	6,650.6
WV	29.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,691.0	0.0	0.0	0.0	0.0	0.0	2,720.4
Total	147.9	914.0	4,705.1	2,322.5	22.0	0.0	0.5	0.0	1,419.5	0.0	84.1	162.9	2.5	0.0	0.0	46,526.8	4,300.8	3,160.0	302.0	10.4	0.0	64,081.0

Figure 12-4 is a map of unit retirements from 2011 through 2030, with a mapping to unit names in Table 12-9.

Figure 12-4 Map of unit retirements: 2011 through 2030

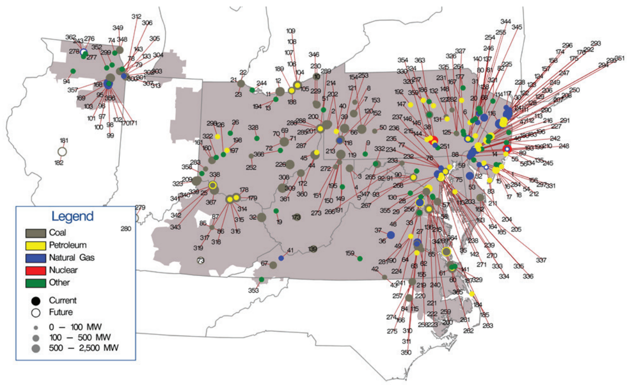


Table 12-9 Unit identification for map of unit retirements: 2011 through 2030

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AC Landfill Units 1 and 2	61	Chesapeake 7-10	121	Elrama 4	181	Kincaid Unit 1	241	Occoquan 1 LF	301	Southeast Chicago CT12	361	Willow Island 2
2	AES Beaver Valley	62	Chesterfield 3	122	Essex 10-11	182	Kincaid Unit 2	242	Ocean County LF	302	Southeast Chicago CT5	362	Winnebago Landfill
3	Albright 1	63	Chesterfield 4	123	Essex 12	183	Kinsley Landfill	243	Orchard Hills LF	303	Southeast Chicago CT6	363	York Generation Facility
4	Albright 2	64	Chesterfield 5	124	Essex 9	184	Kitty Hawk GT 1	244	Ottawa County Project	304	Southeast Chicago CT7	364	Yorktown 1-2
5	Albright 3	65	Chesterfield 6	125	Evergreen Power United Corstack	185	Kitty Hawk GT 2	245	Oyster Creek	305	Southeast Chicago CT8	365	Yorktown 3
6	Allentown CT 1-4	66	Cheswick 1	126	FE DOVETAIL 1 CT	186	Koppers Co. IPP	246	PL MARTINS CREEK 1-4 CT	306	Southeast Chicago GT10	366	Zanesville Landfill
7	Armstrong 1	67	Clinch River 3	127	FRACKVILLE WHEELABRATOR 1	187	Lake Kingman	247	Parlin NUG	307	Southeast Chicago GT9	367	Zimmer 1
8	Armstrong 2	68	Columbia Dam Hydro	128	Fairless Hills Landfill A	188	Lake Shore 18	248	Pedricktown Cogen CC	308	Sporn 1-4		
9	Arnold (Green Mtn.) Wind Farm	69	Conesville 3	129	Fairless Hills Landfill B	189	Lake Shore EMD	249	Pennsbury Generator Landfill 1	309	Sporn 5		
10	Ashtabula 5	70	Conesville 4	130	Fauquier County Landfill	190	Lanier 1 CT	250	Pennsbury Generator Landfill 2	310	Spruance NUG1 (Rich 1-2)		
11	Avon Lake 10	71	Conesville 5	131	Fishbach CT 1	191	Laurel Mountain Battery	251	Perryman 2	311	Spruance NUG2 (Rich 3-4)		
12	Avon Lake 7	72	Conesville 6	132	Fishbach CT 2	192	Lock Haven CT 1	252	Picway 5	312	State Line 3		
13	Avon Lake 9	73	Cooper 1	133	Fisk Street 19	193	Logan	253	Piney Creek NUG	313	State Line 4		
14	BC Landfill	74	Countryside Landfill	134	Forked River Unit 1	194	Lorain 1 LF	254	Portland 1	314	Stuart 1		
15	BL England 1	75	Crane 1	135	Forked River Unit 2	195	MEA NUG (WVU)	255	Portland 2	315	Stuart 2		
16	BL England 2	76	Crane 2	136	GUDE Landfill	196	MH50 Markus Hook Co-gen	256	Possum Point 3	316	Stuart 3		
17	BL England 3	77	Crane GT1	137	Gilbert 1-4	197	Mad River CTs A	257	Possum Point 4	317	Stuart 4		
18	BL England Diesel Units 1-4	78	Crawford 7	138	Glen Gardner 1-8	198	Mad River CTs B	258	Possum Point 5	318	Stuart Diesels 1-4		
19	Balls Gap Battery Facility	79	Crawford 8	139	Glen Lyn 5-6	199	Manchester 1 LF	259	Potomac River 1	319	Stuart Diesels 1-4		
20	Barbados AES Battery	80	Cromby 1	140	Glendon LF	200	Mansfield 1	260	Potomac River 2	320	Sunbury 1-4		
21	Bay Shore 2	81	Cromby 2	141	Gosport 1 F	201	Mansfield 2	261	Potomac River 3	321	Sussex County LF		
22	Bay Shore 3	82	Cromby D	142	Gould Street Generation Station	202	Mansfield 3	262	Potomac River 4	322	Tait Battery		
23	Bay Shore 4	83	Cumberland CT 1	143	Grand Ridge Energy IV battery component	203	McKee 1	263	Potomac River 5	323	Tanners Creek 1-4		
24	Bayonne Cogen Plant (CC)	84	DINWIDDIE 1 CT	144	Harrisburg 4 CT	204	McKee 2	264	Pottstown LF (Moser)	324	Three Mile Island Unit 1		
25	Beckjord Battery Unit 2	85	Dale 1-2	145	Harrisburg CT 1	205	McKee 3	265	R Paul Smith 3	325	Titus 1		
26	Bellefontaine Landfill Generating Station	86	Dale 3	146	Harrisburg CT 2	206	Mercer 1	266	R Paul Smith 4	326	Titus 2		
27	Bellemeade	87	Dale 4	147	Harrisburg CT 3	207	Mercer 2	267	Reichs Ford Road Landfill Generator	327	Titus 3		
28	Benning 15	88	Deepwater 1	148	Harwood 1-2	208	Mercer 3	268	Riverside 4	328	Trent Battery Storage		
29	Benning 16	89	Deepwater 6	149	Hatfield's Ferry 1	209	Miami Fort 6	269	Riverside 6	329	VP Virginia Beach		
30	Bergen 3	90	Dickerson CT1	150	Hatfield's Ferry 2	210	Mickleton CT1	270	Riverside 7	330	Viking Energy NUG		
31	Bethlehem Renewable Energy Generator (Landfill)	91	Dickerson Unit 1	151	Hatfield's Ferry 3	211	Middle 1-3	271	Riverside 8	331	Vineland West CT		
32	Big Sandy 2	92	Dickerson Unit 2	152	Homer City 1	212	Missouri Ave B,C,D	272	Riversville 5	332	WARRIOR RUN 2 BT		
33	Birchwood Plant	93	Dickerson Unit 3	153	Homer City 2	213	Mitchell 2	273	Riversville 6	333	Wagner 1		
34	Brandon Shores 1	94	Dixon Lee Landfill Generator	154	Homer City 3	214	Mitchell 3	274	Roanoke Valley 1	334	Wagner 2		
35	Brandon Shores 2	95	ELWOOD CT 1	155	Hopewell James River Cogeneration	215	Modern Power Landfill NUG	275	Roanoke Valley 2	335	Wagner 3		
36	Bremo 3	96	ELWOOD CT 2	156	Howard Down 10	216	Monmouth NUG landfill	276	Rockford CT11	336	Wagner 4		
37	Bremo 4	97	ELWOOD CT 3	157	Hudson 1	217	Montour ATG	277	Rockford CT12	337	Wagner CT 1		
38	Brunner Island Diesels	98	ELWOOD CT 4	158	Hudson 2	218	Morgantown CT 5	278	Rockford CT21	338	Walter C Beckjord 1		
39	Brunot Island 1B	99	ELWOOD CT 5	159	Hurt NUG	219	Morgantown CT 6	279	Rockport Unit 1	339	Walter C Beckjord 2		
40	Brunot Island 1C	100	ELWOOD CT 6	160	Hutchings 1-3, 5-6	220	Morgantown CT1	280	Rockport Unit 2	340	Walter C Beckjord 3		
41	Buchanan Units 1 and 2	101	ELWOOD CT 7	161	Hutchings 4	221	Morgantown CT2	281	Rockville CT	341	Walter C Beckjord 4		
42	Buggs Island 1 (Mecklenberg)	102	ELWOOD CT 8	162	Indian River CT10	222	Morgantown Unit 1	282	Rolling Hills Landfill Generator	342	Walter C Beckjord 5-6		
43	Buggs Island 2 (Mecklenberg)	103	ELWOOD CT 9	163	Indian River 1	223	Morgantown Unit 2	283	SMART Paper	343	Walter C Beckjord GT 1-4		
44	Burger 3	104	Eastlake 1	164	Indian River 3	224	Morris Landfill Generator	284	Salem County LF	344	Warren County Landfill		
45	Burger EMD	105	Eastlake 2	165	Indian River 4	225	Morris Road 1 D	285	Sammis 1-4	345	Warren County NUG		
46	Burlington 8,11	106	Eastlake 3	166	Ingenco Petersburg	226	Muskingum River 1-5	286	Sammis Diesel Units	346	Warren Evergreen CT1		
47	Burlington 9	107	Eastlake 4	167	Jenkins CT 1-2	227	National Park 1	287	Sammis Unit 5	347	Warrior Run		
48	Buzzard Point East Banks 1,2,4-8	108	Eastlake 5	168	Joliet 6	228	New Bay Cogen CC	288	Sammis Unit 6	348	Waukegan 7		
49	Buzzard Point West Banks 1-9	109	Eastlake 6	169	Joliet 7	229	Niles 1	289	Sammis Unit 7	349	Waukegan 8		
50	Cambria CoGen	110	Easton Diesel Unit 8	170	Joliet 8	230	Niles 2	290	Schuylkill 1	350	Weakley CT		
51	Carbon Limestone LF	111	Eddystone 1	171	Joliet Energy Storage	231	Northeastern Power NEPCO	291	Schuylkill Diesel	351	Werner 1-4		
52	Carlls Corner CT1	112	Eddystone 2	172	Kammer 1-3	232	Notch Cliff GT1	292	Sewaren 1	352	West Chicago Energy Storage		
53	Carlls Corner CT2	113	Eddystone Unit 3	173	Kanawha River 1-2	233	Notch Cliff GT2	293	Sewaren 2	353	West Kingsport LF		
54	Cates Road Solar	114	Eddystone Unit 4	174	Kearny 10	234	Notch Cliff GT3	294	Sewaren 3	354	West Shore CT 1-2		
55	Cedar 1	115	Edgecomb NUG (Rocky 1-2)	175	Kearny 11	235	Notch Cliff GT4	295	Sewaren 4	355	Westport 5		
56	Cedar 2	116	Edison 1-3	176	Kearny 9	236	Notch Cliff GT5	296	Sewaren 6	356	Will County 3		
57	Chalk Point Unit 1	117	Elmwood Park Power	177	Keystone Recovery (Units 1 - 7)	237	Notch Cliff GT6	297	Sherman Avenue CT1	357	Will County 4		
58	Chalk Point Unit 2	118	Elrama 1	178	Killen 2	238	Notch Cliff GT7	298	Sidney Unit 5	358	Willey Energy Storage		
59	Chambers CCLP	119	Elrama 2	179	Killen CT	239	Notch Cliff GT8	299	Solberg 1 BT	359	Williamsport-Lycoming CT 1-2		
60	Chesapeake 1-4	120	Elrama 3	180	Kimberly Clark Generator	240	Oaks Landfill	300	Southeast Chicago CT11	360	Willow Island 1		

Current Year Generation Retirements

Table 12-10 shows that in 2025, 1,000.3 MW of generation retired. The largest generator that retired in 2025 was the 410.0 MW Indian River 4 coal fired steam unit located in the DPL Zone. Of the 1,000.3 MW of generation that retired in 2025, 410.0 MW (41.0 percent) were located in the DPL Zone.

Table 12-10 Unit deactivations: 2025

Owner	Unit Name	ICAP (MW)	Unit Type	Zone Name	Age (Years)	Retirement Date
NRG Energy Inc	Indian River 4	410.0	Steam-Coal	DPL	44	24-Feb-25
NextEra Energy, Inc.	Manchester 1 LF	5.0	RICE-Other	JCPLC	28	01-Apr-25
The Goldman Sachs Group Inc.	Cates Road Solar	2.5	Solar	ACEC	13	01-Apr-25
Pennoni Associates Inc	Morris Road 1 D	2.0	RICE-Oil	PECO	13	31-May-25
Hull Street Energy LLC	ELWOOD CT 8	150.0	CT-Natural Gas	COMED	24	01-Jun-25
Hull Street Energy LLC	ELWOOD CT 9	150.0	CT-Natural Gas	COMED	24	01-Jun-25
Talen Energy Corporation	Wagner 1	126.0	Steam-Natural Gas	BGE	69	01-Jun-25
Talen Energy Corporation	Wagner CT 1	12.9	CT-Oil	BGE	58	01-Jun-25
NextEra Energy, Inc.	Ocean County LF	9.1	RICE-Other	JCPLC	28	01-Jul-25
The AES Corporation	Laurel Mountain Battery	27.4	Battery	APS	14	01-Jul-25
LS Power Equity Partners, L.P.	Buchanan Units 1 and 2	80.0	CT-Natural Gas	AEP	23	02-Jul-25
Sumitomo Corporation	Willey Energy Storage	6.0	Battery	DUKE	10	02-Sep-25
Renergy, Inc.	FE DOVETAIL 1 CT	0.9	RICE-Other	ATSI	9	24-Sep-25
ArcelorMittal	Warren Evergreen CT1	16.5	Combined Cycle	ATSI	9	01-Oct-25
Rockland Capital Energy Investments, LLC	Sidney Unit 5	2.0	RICE-Oil	DAY	57	08-Oct-25
Total		1,000.3				

Planned Generation Retirements

Table 12-11 shows that, as of December 31, 2025, there were 8,335.4 MW of generation that have requested retirement after December 31, 2025. Of the 8,335.4 MW requesting retirement, 5,117.0 MW (61.4 percent) are coal fired steam units. Of the 8,335.4 MW of planned retirements, 2,620.0 MW (31.4 percent) are located in the AEP Zone. Of the generation requesting retirement in the AEP Zone, 2,620.0 MW (100.0 percent) are coal fired steam units.

Table 12-11 Planned retirement of units: December 31, 2025

Owner	Unit Name	ICAP (MW)	Unit Type	Zone Name	Projected Deactivation Date
Constellation Energy Generation, LLC	Eddystone Unit 3	380.0	Steam-Natural Gas	PECO	24-Feb-26
Constellation Energy Generation, LLC	Eddystone Unit 4	380.0	Steam-Natural Gas	PECO	24-Feb-26
Hull Street Energy LLC	ELWOOD CT 1	150.0	CT-Natural Gas	COMED	01-Jun-26
Hull Street Energy LLC	ELWOOD CT 2	150.0	CT-Natural Gas	COMED	01-Jun-26
Hull Street Energy LLC	ELWOOD CT 3	150.0	CT-Natural Gas	COMED	01-Jun-26
Hull Street Energy LLC	ELWOOD CT 4	150.0	CT-Natural Gas	COMED	01-Jun-26
Electric Power Development Co. Ltd.	ELWOOD CT 5	150.0	CT-Natural Gas	COMED	01-Jun-26
Electric Power Development Co. Ltd.	ELWOOD CT 6	150.0	CT-Natural Gas	COMED	01-Jun-26
Electric Power Development Co. Ltd.	ELWOOD CT 7	150.0	CT-Natural Gas	COMED	01-Jun-26
NRG Energy Inc	Indian River CT10	16.4	CT-Oil	DPL	01-Jun-26
Bridgepoint Group PLC	Cumberland CT 1	90.8	CT-Natural Gas	ACEC	01-Jun-27
Hull Street Energy LLC	Forked River Unit 1	34.0	CT-Natural Gas	JCPLC	01-Jun-27
Hull Street Energy LLC	Forked River Unit 2	31.0	CT-Natural Gas	JCPLC	01-Jun-27
LS Power Equity Partners, L.P.	Rockford CT11	149.1	CT-Natural Gas	COMED	01-Jun-27
LS Power Equity Partners, L.P.	Rockford CT12	147.8	CT-Natural Gas	COMED	01-Jun-27
LS Power Equity Partners, L.P.	Rockford CT21	153.0	CT-Natural Gas	COMED	01-Jun-27
Bridgepoint Group PLC	Sherman Avenue CT1	84.3	CT-Natural Gas	ACEC	01-Jun-27
Vistra Energy Corp	Kincaid Unit 1	554.0	Steam-Coal	COMED	30-Nov-27
Vistra Energy Corp	Kincaid Unit 2	554.0	Steam-Coal	COMED	30-Nov-27
American Electric Power Company, Inc.	Rockport Unit 1	1,320.0	Steam-Coal	AEP	31-Dec-28
American Electric Power Company, Inc.	Rockport Unit 2	1,300.0	Steam-Coal	AEP	31-Dec-28
Talen Energy Corporation	Brandon Shores 1	635.0	Steam-Coal	BGE	31-May-29
Talen Energy Corporation	Brandon Shores 2	638.0	Steam-Coal	BGE	31-May-29
Talen Energy Corporation	Wagner 3	305.0	Steam-Oil	BGE	31-May-29
Talen Energy Corporation	Wagner 4	397.0	Steam-Oil	BGE	31-May-29
East Kentucky Power Cooperative, Inc	Cooper 1	116.0	Steam-Coal	EKPC	31-Dec-30
Total		8,335.4			

In addition to the 8,335.4 MW of announced unit retirements as of December 31, 2025, there are significantly more unit retirements expected as a result of environmental regulations and for economic reasons.[51]

Generation Queue[52]

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.[53] 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. But the behavior of project developers also creates issues with queue management and exacerbates the barriers.

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. Projects submitted to the queue undergo a deficiency review to ensure that all required information is provided. A queue position is assigned once the project has met the submission requirements. Projects that do not meet submission requirements are removed from the queue.

51 For more information, see *2025 Annual State of the Market Report for PJM*: Volume 2, Section 7: Net Revenue.
52 Unless otherwise noted, the queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.
53 See OATT Parts IV & VI.

In 2022, after a lengthy stakeholder process (Interconnection Process Reform Task Force (IPRTF)) PJM filed significant changes to improve overall queue management. On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions modifying how PJM manages the new services queue.[54] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[55] This change will allow projects to move forward based on a first ready/first out analysis, where readiness is demonstrated through site control and financial milestones and there is an option to exit the study process early based on system impacts.

The new cycle process also includes defining progress to completion through three phases, with a customer decision at the end of each. The new cycle process requires a stronger definition of site control, and includes readiness deposits (some of which are nonrefundable) based on the phase of development. Additional process modifications include limits to technology changes, improvements to the application review phase, removal of optional interconnection study processes, modifications to the study schedules to reduce the number of restudies required in the event of project modifications, adjusting the queue window schedule to coincide with the previous clusters' milestones, and modifications to cost responsibility by assigning responsibility to all projects within a queue cycle. The new cycle process should help to reduce backlog and to remove projects that are not viable earlier to help improve the overall efficiency of the queue process.

The transition to the new cycle process began on July 10, 2023. The last open series queue prior to July 10, 2023, was AJ1. The new cycle process includes a transition which treats projects based on their series queue status. All projects through series queue window AD2 will continue as part of the series queue process. The transition process assigned series queue projects in queue windows AE1 through AH1 to transition cycle 1 (TC1) and transition cycle 2 (TC2) and also provides for the expedited treatment (fast track) of projects submitted in the AE1 through AG1 queue windows with upgrade costs less than $5 million. The start of the transition to the new cycle process on July 10, 2023, also started the 60 day readiness review period for active projects in the AE1 through AG1 queues. During this time, project developers provided evidence of site control and provided the necessary readiness deposit.[56] Those projects in the AE1 through AG1 series queues that had not yet received an interconnection service agreement or a wholesale market power agreement and also met readiness requirements were reviewed to determine if they were eligible for the fast track process, or if they will be studied as part of transition cycle 1. Of the 734 projects in queues AE1 through AG1 reviewed, 306 projects (41.7 percent) qualified for the expedited process, 312 projects (42.5 percent) were assigned to transition cycle 1 and 116 projects (15.8 percent) were withdrawn from the queue.

The transition process must also account for the fact that PJM significantly underestimated the level of CIRs required for intermittent resources. PJM had required only CIRs equal to the ELCC rating of intermittent resources when in fact those resources required CIRs equal to the maximum output that contributed to the ELCC rating. In general, CIRs were understated by the difference between the ELCC derating factor and the maximum facility output of the intermittent resource. PJM filed revised rules and FERC approved them.[57] PJM has created a process to permit such resources to increase their CIRs to the required level through appropriate investments in interconnection facilities. This process will occur coincident with the start of the new service request Cycle 1.

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.[58]

54 181 FERC ¶ 61,162 (2022).

55 See "Interconnection Process Reform," presented at April 27, 2022 meeting of the Members Committee. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.

56 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 03 (September 25, 2025) for a complete list of all readiness requirements.

57 183 FERC ¶61,009.

58 Once implemented, the approved solutions from PJM's Interconnection Process Reform Task Force (IPRTF) should result in improvements in these areas.

New Service Requests Serial Process

Interconnection Process Studies and Agreements[59]

Prior to implementation of the new cycle process, PJM used a serial service process. In the study stage of the interconnection planning serial process, a series of studies were performed to determine the feasibility, impact, and cost of projects in the queue. Table 12-12 is an overview of the studies PJM performed in the study stage of the interconnection serial process. System impact and facilities studies were often redone when a project was withdrawn in order to determine the impact on the projects remaining in the queue.

Table 12-12 Interconnection planning serial process: study stage

Study	Purpose
Feasibility Study	The feasibility study determines preliminary estimates of the type, scope, cost and lead time for construction of facilities required to interconnect the project.
System Impact Study	The system impact study is a comprehensive regional analysis of the impact of adding the new generation and/or transmission facility to the system. The study identifies the system constraints related to the project and the necessary attachment facilities, local upgrades, and network upgrades. The study refines and more comprehensively estimates cost responsibility and construction lead times for facilities and upgrades.
Facilities Study	In the facilities study, stability analysis is performed and the system impact study results are modified as necessary to reflect changes in the characteristics of other projects in the queue.

In addition to the feasibility, system impact and facilities studies, PJM would also perform additional studies under certain circumstances. These studies included the affected systems study, interim deliverability study and the long term firm transmission studies. Table 12-13 is an overview of the additional studies PJM could have performed.

Table 12-13 Interconnection planning serial process: study stage – additional studies

Study	Purpose
Affected System Study	PJM and its neighboring balancing authorities conduct interconnection studies to determine the impacts of interconnection requests on the neighboring transmission system.
Interim Deliverability Studies	Interim deliverability studies are conducted on a periodic basis in support of RPM auctions and other interconnection studies to determine if a new facility may come on line prior to its scheduled date. These studies evaluate the available system capability and provide the customer(s) with the availability of service by planning year. Interim deliverability studies use the same criteria used for the evaluation of the need for reinforcements associated with a project under study.
Long Term Firm Transmission Studies	Transmission service requests that extend beyond the available transfer capability horizon of 18 months are evaluated along with the other requests for service in the PJM new services queue to ensure deliverability. Long term firm transmission studies follow the same feasibility, system impact and facilities study process as new generation.

After the completion of a facility study, the project would enter the construction stage of the interconnection process. The final agreements required depended on the type of project. These agreements included a Construction Service Agreement (CSA), Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement (UCSA), Wholesale Market Participant Agreement (WMPA) or Transmission Service Agreement (TSA). Table 12-14 is an overview of the agreements in the construction stage of the interconnection serial process.

Table 12-14 Interconnection planning serial process: construction stage agreements

Agreement	Purpose
Interconnection Service Agreement (ISA)	An ISA defines the generation or transmission developer's cost responsibility for required system upgrades. For generation interconnection customers, the ISA defines the capacity interconnection rights for a capacity resource and any operational restrictions or other limitations. For transmission interconnection customers, the ISA defines transmission injection and withdrawal rights and applicable incremental delivery, available transfer capability revenue and auction revenue rights.
Interim Interconnection Service Agreements (I-ISA)	If a developer wishes to start project construction activities prior to completion of the generation or transmission interconnection facilities study, the interim ISA would commit the developer to pay all costs incurred for the construction activities being advanced.
Interconnection Construction Service Agreement (CSA)	The CSA defines the standard terms and conditions of the interconnection, including construction responsibility, includes a construction schedule and contains notification and insurance obligations.
Upgrade Construction Service Agreement (USCA)	A new service customer who proposes to make an upgrade to an existing transmission facility or who seeks incremental auction revenue rights (IARRs) will receive an upgrade construction service agreement after their study process is completed.
Wholesale Market Participation Agreement (WMPA)	Developers interconnecting to non-FERC jurisdictional facilities who intend to participate in the PJM wholesale market will receive a three party agreement (WMPA). The WMPA is a non-Tariff agreement which must be filed with the FERC. The WMPA is essentially an ISA without interconnection provisions.

59 See "PJM Manual 14A: New Services Request Process," Rev. 30 (July 26, 2023) for a complete explanation of the interconnection process studies and agreements.

Planned Generation Additions

There were 8,190 generation request projects submitted in the new service request serial process queue from 1997 until the implementation of the new cycle process on July 10, 2023. As a result of the transition to the new services cycle process, 312 projects were moved to transition cycle 1 (TC1). There were 1,347 projects eligible to resubmit for evaluation in transition cycle 2 (TC2). Of those 1,347 eligible projects, 550 projects resubmitted and are now being evaluated in TC2. Of the 1,347 eligible projects, 797 projects did not resubmit, and were withdrawn from the queue. There were 1,070 projects initially entered into the AH2 queue and beyond. Those 1,070 projects are now considered invalid and have been removed from the queue. As a result of the transition to the cycle process, the 8,190 projects in the serial process queue has been reduced to 5,461 projects. Projects that will be evaluated in TC1 and TC2, and those projects no longer eligible to be evaluated in the serial process have been removed from the new service requests serial process metrics. New service requests cycle process metrics are reported separately from the serial process metrics.

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 and from federal and state subsidies and incentives. On December 31, 2025, 41,528.9 MW were in generation request serial queues in the status of active, under construction or suspended, for construction through 2031. 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.[60]

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. Table 12-15 shows the total MW in the serial queues by expected completion year and MW changes in the serial queue between December 31, 2024, and December 31, 2025, for ongoing projects, i.e. projects with the status active, under construction or suspended.[61]

Table 12-15 Serial queue comparison by expected completion year (MW): December 31, 2024 and December 31, 2025[62]

			Year Change	
Year	As of 12/31/2024	As of 12/31/2025	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	0.0	0.0	0.0	0.0%
2012	0.0	0.0	0.0	0.0%
2013	0.0	0.0	0.0	0.0%
2014	0.0	0.0	0.0	0.0%
2015	0.0	0.0	0.0	0.0%
2016	0.0	0.0	0.0	0.0%
2017	0.0	0.0	0.0	0.0%
2018	44.0	44.0	0.0	0.0%
2019	69.1	0.0	(69.1)	(100.0%)
2020	395.6	0.0	(395.6)	(100.0%)
2021	2,266.9	116.0	(2,150.9)	(94.9%)
2022	2,870.9	0.0	(2,870.9)	(100.0%)
2023	3,500.0	250.0	(3,250.0)	(92.9%)
2024	3,112.8	725.2	(2,387.6)	(76.7%)
2025	7,861.0	3,644.0	(4,217.0)	(53.6%)
2026	11,175.2	11,677.6	502.4	4.5%
2027	4,149.1	10,248.1	6,099.0	147.0%
2028	4,057.3	8,612.7	4,555.4	112.3%
2029	1,233.0	3,947.9	2,714.9	220.2%
2030	250.0	1,280.0	1,030.0	412.0%
2031	544.0	983.4	439.4	80.8%
Total	41,528.9	41,528.9	0.0	0.0%

Table 12-16 shows the project status changes in more detail and how scheduled serial queue MW have changed between December 31, 2024, and December 31, 2025. For example, of the total 35,266.7 MW marked as active on December 31, 2024, 7,822.2 MW were withdrawn, 2,068.9 MW were suspended, 7,018.8 MW started construction, and 54.9 MW went into service by December 31, 2025. Analysis of projects that were suspended on December 31, 2024 show that 1,903.6 MW came out of suspension and are now active as of December 31, 2025.

60 See "*PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years*," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf>.

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

62 Unless otherwise noted, wind and solar capacity totals in this section have not been adjusted to reflect derating.

Table 12-16 Change in project status (MW): December 31, 2024, to December 31, 2025

		Status at 12/31/2025				
Status at 12/31/2024	Total at 12/31/2024	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2025)	0.0	0.0	0.0	0.0	0.0	0.0
Active	35,266.7	18,301.9	54.9	7,018.8	2,068.9	7,822.2
In Service	91,775.4	0.0	91,775.4	0.0	0.0	0.0
Under Construction	6,959.6	0.0	2,962.9	3,561.7	300.0	135.0
Suspended	12,137.9	1,903.6	65.0	853.9	7,520.2	1,795.3
Withdrawn	463,122.8	0.0	8.0	0.0	0.0	463,114.8
Total	609,262.3	20,205.4	94,866.2	11,434.4	9,889.1	472,867.2

On December 31, 2025, 41,528.9 were in generation request serial queues in the status of active, suspended or under construction. Table 12-17 shows each status by unit type. Of the 20,205.4 MW in the status of active on December 31, 2025, 1,220.0 MW (6.0 percent) were combined cycle projects. Of the 11,434.4 MW in the status of under construction, 1,668.8 MW (14.6 percent) were combined cycle projects and 7,331.4 MW (64.1 percent) were solar projects. A significant amount of renewable hybrid projects (defined as solar + storage, solar + wind and wind + storage projects) have entered the queue in recent years. Of the 41,528.9 MW in the serial queues in the status of active on December 31, 2025, 1,767.6 MW (8.7 percent) were renewable hybrid projects. Of the 11,434.4 MW in the status of under construction, 161.6 MW (1.4 percent) were renewable hybrid projects.

Table 12-17 Current project status (MW) by unit type: December 31, 2025

	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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	2,062.2	1,220.0	1,057.7	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	12,486.0	1,767.6	0.0	0.0	0.0	0.0	0.0	1,561.0	0.0	20,205.4
Suspended	638.2	1,270.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,769.1	150.0	0.0	0.0	0.0	0.0	0.0	2,061.8	0.0	9,889.1
Under Construction	405.7	1,668.8	60.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	7,331.4	161.6	0.0	36.0	0.0	0.0	0.0	1,726.9	0.0	11,434.4
Total	3,106.1	4,158.8	1,117.7	0.0	0.0	0.0	0.0	51.0	44.0	0.0	0.0	0.0	25,586.5	2,079.2	0.0	36.0	0.0	0.0	0.0	5,349.7	0.0	41,528.9

A significant shift in the distribution of unit types within the PJM footprint continues to develop as renewable, hybrid and other intermittent resources enter the queue, fewer natural gas fired units enter the queue, and coal fired steam units retire. As of December 31, 2025, of the 41,528.9 MW in the generation request serial queues in the status of active, suspended or under construction, 25,586.5 MW (61.6 percent) were solar projects, 5,349.7 MW (12.9 percent) were wind projects, 5,276.5 MW (12.7 percent) were natural gas fired projects (including combined cycle units, CTs, RICE units, and natural gas fired steam units), 2,079.2 MW (5.0 percent) were renewable hybrid projects (solar + storage, solar + wind and wind + storage units), and 36.0 MW (0.09 percent) were coal fired steam projects.

As of December 31, 2025, there were 5,117.0 MW of coal fired steam units and 2,500.0 MW of natural gas units slated for deactivation between January 1, 2026, and December 31, 2030 (See Table 12-11). The ongoing replacement of coal fired steam units by natural gas units will continue to significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure. The growing level of renewables, hybrids and other intermittents will have increasingly significant impacts on the energy and capacity markets.

On December 31, 2025, 30,081.4 MW, on an energy basis, were in generation request serial queues that had reached the construction service agreement milestone or equivalent, in the status of active, suspended or under construction. Table 12-18 shows the status by unit type. Of the 30,081.4 MW, 10,916.9 MW (36.3 percent) had not begun construction, 9,889.1 MW (32.9 percent) began construction, but are now suspended and 9,275.4 MW (30.8 percent) are currently under construction. Reaching the final milestone required prior to construction does not mean a project will immediately begin construction or even that it necessarily will ever begin construction.

Table 12-18 Current status (MW) by unit type for projects that have reached the CSA Milestone: December 31, 2025

	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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	625.0	1,170.0	618.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,519.4	686.6	0.0	0.0	0.0	0.0	0.0	1,297.7	0.0	10,916.9
Suspended	638.2	1,270.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,769.1	150.0	0.0	0.0	0.0	0.0	0.0	2,061.8	0.0	9,889.1
Under Construction	355.7	1,668.8	60.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	5,235.0	161.6	0.0	36.0	0.0	0.0	0.0	1,714.3	0.0	9,275.4
Total	1,618.9	4,108.8	678.3	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	17,523.5	998.2	0.0	36.0	0.0	0.0	0.0	5,073.7	0.0	30,081.4

Table 12-19 shows the total MW in the status of active, in service, under construction, suspended, or withdrawn for each serial queue since the beginning of the RTEP process and the total MW that had been included in each queue. All projects in queues A-Z2 are either in service or have been withdrawn. As of December 31, 2025, there were 41,528.9 MW in serial queues that are not yet in service or withdrawn, of which 9,889.1 MW (23.8 percent) are suspended, 11,434.4 MW (27.5 percent) are under construction and 20,205.4 MW (48.7 percent) have not begun construction.

Table 12-19 Serial queue totals by status (MW): December 31, 2025[63]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	9,102.0	0.0	0.0	17,252.0	26,354.0
B Expired 31-Jan-99	0.0	4,292.4	0.0	0.0	14,958.8	19,251.2
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	1,171.6	0.0	0.0	17,961.8	19,133.4
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	0.0	2,398.8	0.0	0.0	8,129.3	10,528.0
O Expired 31-Jul-05	0.0	1,885.6	0.0	0.0	5,466.8	7,352.4
P Expired 31-Jan-06	0.0	3,290.3	0.0	0.0	5,320.5	8,610.8
Q Expired 31-Jul-06	0.0	3,147.9	0.0	0.0	11,385.7	14,533.6
R Expired 31-Jan-07	0.0	1,886.1	0.0	0.0	20,708.9	22,595.0
S Expired 31-Jul-07	0.0	3,598.4	0.0	0.0	12,396.5	15,994.9
T Expired 31-Jan-08	0.0	4,196.5	0.0	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	716.7	0.0	0.0	16,218.6	16,935.3
U3 Expired 31-Oct-08	0.0	333.0	0.0	0.0	2,635.6	2,968.6
U4 Expired 31-Jan-09	0.0	85.2	0.0	0.0	4,945.0	5,030.2
V1 Expired 30-Apr-09	0.0	197.9	0.0	0.0	2,572.8	2,770.7
V2 Expired 31-Jul-09	0.0	989.9	0.0	0.0	3,641.2	4,631.1
V3 Expired 31-Oct-09	0.0	1,132.0	0.0	0.0	3,822.7	4,954.7
V4 Expired 31-Jan-10	0.0	748.8	0.0	0.0	3,708.0	4,456.8
W1 Expired 30-Apr-10	0.0	567.4	0.0	0.0	5,139.5	5,706.9
W2 Expired 31-Jul-10	0.0	351.7	0.0	0.0	3,051.7	3,403.4
W3 Expired 31-Oct-10	0.0	504.3	0.0	0.0	8,695.9	9,200.2
W4 Expired 31-Jan-11	0.0	1,415.8	0.0	0.0	4,152.6	5,568.4
X1 Expired 30-Apr-11	0.0	1,101.7	0.0	0.0	6,200.6	7,302.3
X2 Expired 31-Jul-11	0.0	3,706.4	0.0	0.0	5,578.4	9,284.7
X3 Expired 31-Oct-11	0.0	109.2	0.0	0.0	7,665.9	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	0.0	6,279.7	8,075.2
Y2 Expired 31-Oct-12	0.0	1,477.2	0.0	0.0	9,636.5	11,113.7
Y3 Expired 30-Apr-13	0.0	1,634.5	0.0	0.0	4,605.2	6,239.6
Z1 Expired 31-Oct-13	0.0	3,283.5	0.0	0.0	4,730.0	8,013.5
Z2 Expired 30-Apr-14	0.0	3,058.7	0.0	0.0	3,037.8	6,096.6
AA1 Expired 31-Oct-14	0.0	4,986.9	78.2	0.0	6,973.4	12,038.5
AA2 Expired 30-Apr-15	550.0	3,031.6	0.0	0.0	12,484.7	16,066.3
AB1 Expired 31-Oct-15	579.0	2,835.6	1,551.0	247.8	15,240.3	20,453.7
AB2 Expired 31-Mar-16	0.0	3,678.5	404.0	92.0	10,968.3	15,142.8
AC1 Expired 30-Sep-16	485.0	5,900.1	693.9	558.0	12,399.0	20,035.9
AC2 Expired 30-Apr-17	783.4	1,584.8	498.8	314.9	9,387.8	12,569.6
AD1 Expired 30-Sep-17	829.0	1,295.7	1,326.7	668.0	7,117.2	11,236.6
AD2 Expired 31-Mar-18	602.0	1,751.1	893.5	1,088.8	15,921.3	20,256.7
AE1 Expired 30-Sep-18	1,415.5	902.4	1,318.9	4,213.0	24,993.1	32,842.8
AE2 Expired 31-Mar-19	2,918.6	1,942.6	1,617.6	1,751.6	20,354.7	28,585.1
AF1 Expired 30-Sep-19	4,204.7	1,212.7	1,244.8	744.7	13,931.8	21,338.8
AF2 Expired 31-Mar-20	3,719.7	393.5	1,235.6	139.8	12,353.2	17,841.7
AG1 Expired 30-Sep-20	4,118.6	72.2	571.4	70.5	13,922.5	18,755.3
AG2 Expired 31-Mar-21	0.0	1.0	0.0	0.0	0.0	1.0
Total	20,205.4	94,866.2	11,434.4	9,889.1	472,867.2	609,262.3

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

Table 12-20 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of December 31, 2025, 41,528.9 MW were in generation request serial queues for construction through 2031. Table 12-20 also shows the planned retirements for each zone.

Table 12-20 Serial queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): December 31, 2025[64]

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total Queue Capacity	Planned Retirements
EMAAC	ACEC	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	160.9	38.0	0.0	0.0	0.0	0.0	0.0	432.0	0.0	680.9	175.1
	DPL	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	751.0	16.6	0.0	0.0	0.0	0.0	0.0	255.1	0.0	1,031.7	16.4
	JCPLC	310.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	119.2	70.0	0.0	0.0	0.0	0.0	0.0	816.0	0.0	1,315.2	65.0
	PECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	760.0
	PSEG	525.0	51.1	0.0	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	0.0	0.0	0.0	0.0	582.1	0.0
	REC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EMAAC Total	894.0	51.1	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	1,037.1	124.6	0.0	0.0	0.0	0.0	0.0	1,503.1	0.0	3,653.9	1,016.5
SWMAAC	BGE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,975.0
	PEPCO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0
	SWMAAC Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	1,975.0
WMAAC	MEC	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	224.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	244.6	0.0
	PE	160.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,243.2	0.0	0.0	0.0	0.0	0.0	0.0	109.9	0.0	1,513.1	0.0
	PPL	170.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	628.2	60.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	858.2	0.0
	WMAAC Total	350.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,096.0	60.0	0.0	0.0	0.0	0.0	0.0	109.9	0.0	2,615.9	0.0
Non-MAAC	AEP	819.2	1,150.0	0.0	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	11,710.1	809.0	0.0	36.0	0.0	0.0	0.0	816.2	0.0	15,391.5	2,620.0
	AMPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	0.0
	APS	20.0	1,915.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,117.6	380.0	0.0	0.0	0.0	0.0	0.0	160.0	0.0	3,622.6	0.0
	ATSI	0.0	940.0	458.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,359.8	57.7	0.0	0.0	0.0	0.0	0.0	297.7	0.0	3,113.9	0.0
	COMED	180.0	102.7	60.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,120.9	19.9	0.0	0.0	0.0	0.0	0.0	2,384.6	0.0	3,868.1	2,607.9
	DAY	125.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	806.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	931.3	0.0
	DUKE	52.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	149.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	201.2	0.0
	DLCO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DOM	665.7	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,728.6	628.0	0.0	0.0	0.0	0.0	0.0	78.2	0.0	7,669.5	0.0
	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	381.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	381.0	116.0
	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	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	0.0	0.0	0.0
	Non-MAAC Total	1,862.1	4,107.7	1,117.7	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	22,413.4	1,894.6	0.0	36.0	0.0	0.0	0.0	3,736.7	0.0	35,219.1	5,343.9
Total		3,106.1	4,158.8	1,117.7	0.0	0.0	0.0	0.0	51.0	44.0	0.0	0.0	0.0	25,586.5	2,079.2	0.0	36.0	0.0	0.0	0.0	5,349.7	0.0	41,528.9	8,335.4

Withdrawn Projects

The serial queue contains a substantial number of projects that are not likely to be built. The serial 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.[65] The impact and facilities studies are performed using the full amount of planned generation in the queues.

Table 12-21 shows the milestone status when projects were withdrawn, for all withdrawn projects in the serial queue. Of the 3,750 projects withdrawn as of December 31, 2025, 1,577 (42.1 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 3,750 projects withdrawn, 840 projects (22.4 percent) were withdrawn after the completion of a Construction Service Agreement as of December 31, 2025.

Table 12-21 Last milestone at time of withdrawal: January 1, 1997 through December 31, 2025

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days	MW Withdrawn
Never Started	513	13.7%	81	868	53,163.6
Feasibility Study	1,064	28.4%	290	1,633	196,263.0
System Impact Study	907	24.2%	829	3,248	115,206.2
Facilities Study	426	11.4%	1,295	4,107	58,620.1
Construction Service Agreement (CSA) or beyond	840	22.4%	1,513	7,864	49,614.4
Total	3,750	100.0%			472,867.2

64 This data includes only projects with a status of active, under construction, or suspended.
65 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 58 (December 17, 2025).

Average Time in Serial Queue

Table 12-22 shows the time spent at various stages in the serial queue process and the completion time for the studies performed. For completed projects, there is an average time of 1,266 days, or 3.5 years, between entering a serial queue and going into service. For withdrawn projects, there is an average time of 798 days, or 2.2 years, between entering a serial queue and withdrawing.

Table 12-22 Project serial queue times by status (days): December 31, 2025[66]

Status	Average (Days)	Standard Deviation	Maximum
Active	2,352	413	3,898
In-Service	1,266	876	6,628
Suspended	2,633	414	3,775
Under Construction	2,700	516	4,152
Withdrawn	798	799	7,864

Table 12-23 presents information on the time in the stages of the serial queue for those projects not yet in service or already withdrawn. Of the 435 projects in the serial queue, in the status of active, under construction or suspended, as of December 31, 2025, three (0.7 percent) had a completed system impact study, 116 (26.7 percent) had a completed facilities study and 316 (72.6 percent) had a completed construction service agreement.

Table 12-23 Project serial queue times by milestone (days): December 31, 2025

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	0	0.0%	0	0
Feasibility Study	0	0.0%	0	0
System Impact Study	3	0.7%	2,127	2,336
Facilities Study	116	26.7%	2,166	2,655
Construction Service Agreement (CSA) or beyond	316	72.6%	2,637	4,152
Total	435	100.0%		

Table 12-24 shows the time spent in the serial queue by fuel type, and year the project entered the queue, for projects that are in service. The time from when a project enters the serial queue to the time the project goes in service has generally been decreasing compared to the period prior to 2017 although there are significant exceptions. For example, for a battery project entering the serial queue in 2015, there was an average of 2,062 days from the time it entered the queue until it went in service, compared to 1,409 days when entering the queue in 2018.

66 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 12-24 Average time in serial queue (days) by fuel type and year submitted (In Service Projects): December 31, 2025[67]

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Battery	983	609	417	710	789	2,062	941		1,409	972	1,084					
CC	1,310	1,426	1,663	1,419	1,175	1,138	1,199	1,013	1,140	1,069	659					
CT - Natural Gas	1,131	804	953	1,073	1,409	619	1,566	1,192	938	317	805					
CT - Oil	717		259							280	349					
CT - Other	729	634	954	1,248	718	360										
Fuel Cell						827				280						
Hydro - Pumped Storage						1,402										
Hydro - Run of River			1,325	614	332		580	426	606							
Nuclear	885	866		1,234			2,434	1,113	1,772							
RICE - Natural Gas			1,702	1,053	1,332	798		250		770						
RICE - Oil						1,849										
RICE - Other	638	1,385	1,479	241	627	622	491		466							
Solar	1,701	1,395	969	1,014	1,009	1,899	1,977	2,045	1,762	1,521	1,135					
Solar + Storage						635	322		553		809					
Solar + Wind																
Steam - Coal	745		513	1,010	583	853	684	647	1,810	2,139						
Steam - Natural Gas				1,182		421	751				1,286					
Steam - Oil																
Steam - Other	256	838	643													
WInd	2,748	2,711	1,750	2,103	1,205	1,463	1,837	1,398	1,289		997					
Wind + Storage							2,680									

Table 12-25 shows 609,262.3 MW have entered PJM generation serial queues from January 1, 1997, through June 10, 2023. Table 12-25 presents totals by fuel type and projected in service date as of December 31, 2025. Of the 609,262.3 MW to enter the serial queue, 348,159.4 MW (57.1 percent) were thermal units.

Table 12-25 Total (MW Energy) by unit type and projected in service year: December 31, 2025

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
1997	0.0	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	4,911.0	0.0	0.0	0.0	0.0	0.0	5,686.0
1998	0.0	4,659.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,662.1
1999	0.0	22,573.7	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.0	0.0	0.0	0.0	20.4	0.0	22,603.2
2000	0.0	9,900.8	409.6	0.0	3.8	0.0	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	10,335.3
2001	0.0	7,088.5	432.0	315.0	29.0	0.0	0.0	0.0	165.0	0.0	0.0	0.0	0.0	0.0	0.0	110.6	2.5	0.0	0.0	0.0	0.0	8,142.6
2002	0.0	2,622.2	2,442.0	6.5	0.0	0.0	0.0	107.0	60.0	0.0	0.0	2.9	0.0	0.0	0.0	42.0	10.0	0.0	0.0	65.5	0.0	5,358.1
2003	0.0	4,072.1	638.7	0.0	59.4	0.0	0.0	198.0	46.0	0.0	0.0	17.2	0.0	0.0	0.0	2.0	0.0	0.0	0.0	263.6	0.0	5,297.0
2004	0.0	14,918.2	77.3	33.0	16.1	0.0	0.0	41.0	0.0	8.0	23.3	0.0	0.0	0.0	0.0	42.0	0.0	0.0	0.0	75.0	0.0	15,233.9
2005	0.0	17,149.1	993.0	251.0	42.1	0.0	0.0	0.0	1,693.0	29.0	5.0	7.5	0.0	0.0	0.0	1,880.0	0.0	0.0	0.0	809.9	0.0	22,859.6
2006	0.0	6,033.0	23.3	49.5	43.4	0.0	0.0	147.2	0.0	2.0	30.5	58.5	0.0	0.0	0.0	527.0	0.0	0.0	529.0	1,480.2	0.0	8,923.6
2007	0.0	3,484.6	131.0	17.0	84.0	0.0	0.0	2.5	174.0	19.5	0.0	86.6	0.0	0.0	0.0	750.0	5.0	0.0	68.0	1,087.8	0.0	5,910.0
2008	1.0	7,003.4	628.0	59.3	38.4	0.0	0.0	2.9	331.0	0.0	0.0	57.6	3.3	0.0	0.0	254.5	101.0	0.0	20.0	2,098.6	0.0	10,599.0
2009	120.0	2,717.2	257.7	108.6	118.7	0.0	340.0	252.5	0.0	0.0	0.0	41.2	28.7	0.0	0.0	1,058.0	40.0	0.0	6.0	4,351.5	0.0	9,440.2
2010	16.0	1,912.9	137.8	83.9	320.7	0.0	16.0	94.9	301.0	10.5	0.0	15.8	231.4	0.0	0.0	5,599.0	0.0	0.0	80.8	9,286.1	0.0	18,106.8
2011	52.5	10,887.5	816.4	23.0	110.0	0.0	0.0	27.0	512.0	0.0	16.0	41.8	1,818.5	0.0	0.0	9,614.0	5.5	0.0	108.9	5,355.2	0.0	29,388.2
2012	27.0	13,786.8	389.5	310.0	121.3	0.0	0.0	82.9	391.0	0.0	6.4	2.0	1,892.3	0.0	0.0	3,407.0	0.0	0.0	426.6	7,635.1	0.0	28,477.8
2013	73.0	9,252.2	62.5	730.5	78.9	0.0	0.0	219.0	238.0	0.0	10.0	113.0	674.9	0.0	0.0	1,949.0	44.0	0.0	254.1	8,057.4	0.0	21,756.5
2014	159.1	7,105.5	0.0	684.0	96.0	0.0	0.0	1,120.0	74.0	0.0	0.0	13.3	904.5	0.0	0.0	3,288.0	0.0	0.0	63.8	11,758.7	186.0	25,452.9
2015	214.6	15,591.3	417.4	42.0	22.0	0.0	0.0	378.5	147.8	19.5	9.0	3.8	1,240.1	0.0	0.0	1,271.5	0.0	0.0	81.5	4,161.6	0.0	23,600.5
2016	422.5	16,553.3	332.1	0.0	144.9	2.8	0.0	71.2	4,082.0	46.9	0.0	30.2	1,737.6	3.4	0.0	50.0	40.0	0.0	107.8	4,459.3	0.0	28,083.9
2017	134.1	17,489.5	835.0	401.0	135.0	2.0	0.0	86.2	1,640.0	283.6	0.0	18.2	2,158.3	0.0	0.0	47.0	606.5	0.0	7.2	3,010.2	0.0	26,853.7
2018	175.0	17,902.0	404.9	0.0	11.6	1.1	34.0	12.5	1,644.0	95.0	0.0	41.0	3,369.9	0.6	0.0	148.0	57.0	0.0	0.0	5,135.7	0.0	29,032.3
2019	303.0	14,793.4	1,036.8	14.0	0.0	0.0	0.0	20.5	0.0	79.7	0.0	33.6	7,203.3	629.8	0.0	1,710.0	0.0	0.0	16.0	5,377.6	16.3	31,233.9
2020	621.7	7,243.7	1,173.0	0.0	0.0	2.1	0.0	2.4	128.0	39.9	4.0	0.8	5,726.6	615.5	0.0	20.0	64.0	0.0	0.0	8,886.7	0.0	24,528.4
2021	1,176.9	17,904.2	687.3	4.0	0.0	0.0	0.0	48.0	0.0	15.7	0.0	0.0	13,387.0	2,052.0	0.0	47.0	6.0	0.0	62.5	4,817.7	90.0	40,298.3
2022	2,677.1	12,723.2	1,629.3	0.0	0.0	0.0	1,000.0	28.0	0.0	20.0	0.0	0.0	10,837.9	1,578.3	0.0	0.0	0.0	0.0	0.0	2,249.7	0.0	32,743.4
2023	2,463.2	12,105.0	1,439.7	13.0	0.0	3.0	0.0	36.6	54.2	0.0	0.0	0.0	12,581.0	5,400.9	0.0	0.0	0.0	0.0	0.0	1,987.4	0.0	36,084.0
2024	619.5	4,522.5	646.0	0.0	0.0	0.0	0.0	12.0	1,594.0	0.0	0.0	0.0	7,571.5	1,041.1	0.0	0.0	5.0	0.0	0.0	4,228.2	0.0	20,239.8
2025	273.4	146.7	463.0	0.0	0.0	0.0	0.0	16.8	0.0	0.0	0.0	0.0	5,464.0	142.5	0.0	29.0	0.0	0.0	0.0	4,009.6	0.0	10,544.9
2026	701.0	2,785.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,389.6	300.3	0.0	0.0	0.0	0.0	0.0	3,211.6	0.0	14,387.5
2027	783.2	1,826.1	735.0	0.0	0.0	0.0	200.0	0.0	0.0	0.0	0.0	0.0	8,048.4	373.0	0.0	0.0	0.0	0.0	0.0	1,661.1	0.0	13,626.8
2028	969.0	50.0	19.3	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	6,223.1	1,226.0	0.0	0.0	0.0	0.0	0.0	1,413.3	0.0	9,951.7
2029	830.0	595.0	599.0	0.0	0.0	0.0	0.0	9.5	0.0	0.0	0.0	0.0	2,443.9	500.0	0.0	0.0	0.0	0.0	0.0	2,509.7	0.0	7,487.1
2030	250.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,350.0
2031	0.0	0.0	439.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	150.0	394.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	983.4
Total	13,062.6	288,172.5	18,298.1	3,145.3	1,478.3	10.9	1,590.0	3,068.0	13,275.0	669.3	104.2	586.2	102,185.9	14,257.3	0.0	36,783.6	986.5	0.0	1,832.2	109,464.2	292.3	609,262.3

67 A blank cell in this table means that no project of that fuel type, which was submitted to the queue in that year, subsequently went in service.

Table 12-26 shows there were 41,528.9 MW in the serial queue in the status of active, under construction and suspended as of December 31, 2025. Table 12-26 presents totals by fuel type and projected in service date. Of the 41,528.9 MW, 5,312.5 MW (12.8 percent) are thermal units. Of the 40,393.8 MW with projected in service dates between 2025 and 2031, 5,276.5 MW (12.7 percent) are thermal units.

Table 12-26 Total (MW Energy) by unit type and projected in service year (active, under construction and suspended): December 31, 2025

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
1997	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1998	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1999	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2000	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2001	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2002	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2003	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2004	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2006	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2007	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2008	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2009	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2010	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2011	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2012	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2014	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2015	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2016	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2017	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.0	0.0	0.0	0.0	80.0	0.0	116.0
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	250.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	250.0
2024	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	598.6	6.6	0.0	0.0	0.0	0.0	0.0	80.0	0.0	725.2
2025	137.9	102.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,014.5	0.0	0.0	0.0	0.0	0.0	0.0	389.0	0.0	3,644.0
2026	661.0	2,210.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,212.4	267.8	0.0	0.0	0.0	0.0	0.0	2,326.4	0.0	11,677.6
2027	662.2	1,201.1	60.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,169.0	294.8	0.0	0.0	0.0	0.0	0.0	861.0	0.0	10,248.1
2028	845.0	50.0	19.3	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	5,218.1	1,016.0	0.0	0.0	0.0	0.0	0.0	1,413.3	0.0	8,612.7
2029	510.0	595.0	599.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,943.9	100.0	0.0	0.0	0.0	0.0	0.0	200.0	0.0	3,947.9
2030	250.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,030.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,280.0
2031	0.0	0.0	439.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	150.0	394.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	983.4
Total	3,106.1	4,158.8	1,117.7	0.0	0.0	0.0	0.0	51.0	44.0	0.0	0.0	0.0	25,586.5	2,079.2	0.0	36.0	0.0	0.0	0.0	5,349.7	0.0	41,528.9

Table 12-27 shows there were 472,867.2 MW withdrawn from the serial queue from January 1, 1997, through December 31, 2025. Table 12-27 presents totals by fuel type and projected in service date. Of the 472,867.2 MW withdrawn from the serial queue, 280,279.1 MW (59.3 percent) were thermal units. Of the 15,487.0 MW withdrawn with projected in service dates between 2025 and 2031, 2,382.0 MW (15.4 percent) were thermal units.

Table 12-27 Total (MW Energy) by unit type and projected in service year (withdrawn): December 31, 2025

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
1997	0.0	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	4,911.0	0.0	0.0	0.0	0.0	0.0	5,686.0
1998	0.0	4,659.0	0.0	0.0	3.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,662.1
1999	0.0	22,573.7	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	22,575.8
2000	0.0	9,900.8	0.0	0.0	3.8	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	9,904.5
2001	0.0	6,988.5	0.0	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	51.6	0.0	0.0	0.0	0.0	0.0	7,045.1
2002	0.0	14.2	0.0	0.0	0.0	0.0	0.0	0.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	28.0	0.0	0.0	0.0	50.5	0.0	137.7
2003	0.0	1,287.1	0.0	0.0	59.4	0.0	0.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	73.6	0.0	1,422.1
2004	0.0	12,073.2	0.0	0.0	12.0	0.0	0.0	41.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	12,201.2
2005	0.0	17,134.0	0.0	1.0	42.1	0.0	0.0	0.0	0.0	0.0	5.0	0.0	0.0	0.0	0.0	1,860.0	0.0	0.0	0.0	802.4	0.0	19,844.5
2006	0.0	4,847.0	0.0	0.0	43.4	0.0	0.0	142.0	0.0	0.0	30.5	0.0	0.0	0.0	0.0	520.0	0.0	0.0	0.0	1,430.2	0.0	7,013.1
2007	0.0	3,455.0	0.0	0.0	71.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	675.0	0.0	0.0	50.0	554.5	0.0	4,805.6
2008	1.0	6,826.0	0.0	0.0	38.4	0.0	0.0	2.9	18.0	0.0	0.0	0.0	0.0	0.0	0.0	152.0	0.0	0.0	0.0	1,857.0	0.0	8,895.3
2009	120.0	2,618.2	0.0	61.0	113.7	0.0	0.0	252.0	0.0	0.0	0.0	0.0	28.7	0.0	0.0	935.0	0.0	0.0	6.0	3,129.5	0.0	7,264.1
2010	16.0	1,776.9	0.0	81.0	302.5	0.0	0.0	54.9	0.0	0.0	0.0	0.0	168.5	0.0	0.0	5,512.0	0.0	0.0	20.8	7,853.1	0.0	15,785.7
2011	25.1	8,985.5	0.0	0.0	98.6	0.0	0.0	0.0	140.0	0.0	16.0	0.0	1,747.5	0.0	0.0	8,817.0	0.0	0.0	108.0	4,781.0	0.0	24,718.7
2012	20.5	13,711.5	0.5	310.0	87.7	0.0	0.0	82.9	0.0	0.0	6.4	0.0	1,801.8	0.0	0.0	2,751.0	0.0	0.0	426.6	6,534.9	0.0	25,733.9
2013	72.0	9,168.0	0.0	730.0	38.6	0.0	0.0	79.0	34.0	0.0	10.0	0.0	651.0	0.0	0.0	1,861.0	0.0	0.0	254.1	7,686.3	0.0	20,584.1
2014	114.1	6,438.0	0.0	684.0	96.0	0.0	0.0	1,085.1	74.0	0.0	0.0	0.0	809.7	0.0	0.0	3,212.0	0.0	0.0	10.0	11,308.7	0.0	23,831.6
2015	111.6	13,216.5	12.5	42.0	10.7	0.0	0.0	218.0	0.0	0.6	9.0	0.0	1,041.4	0.0	0.0	1,251.0	0.0	0.0	81.5	3,956.6	0.0	19,951.4
2016	400.1	9,812.3	35.4	0.0	144.0	2.0	0.0	71.2	3,980.0	26.0	0.0	11.7	1,484.8	0.0	0.0	50.0	0.0	0.0	107.8	4,181.8	0.0	20,307.1
2017	134.1	13,041.4	696.0	401.0	135.0	1.3	0.0	15.0	1,640.0	263.7	0.0	17.1	1,822.2	0.0	0.0	0.0	0.0	0.0	7.2	2,375.2	0.0	20,549.1
2018	109.5	10,224.0	64.9	0.0	11.6	1.1	0.0	0.0	1,600.0	89.8	0.0	36.2	3,017.5	0.0	0.0	80.0	27.0	0.0	0.0	4,618.0	0.0	19,879.6
2019	303.0	10,812.9	922.8	14.0	0.0	0.0	0.0	15.0	0.0	39.9	0.0	33.6	6,771.8	629.8	0.0	1,710.0	0.0	0.0	16.0	4,286.6	16.3	25,571.6
2020	621.7	5,987.7	1,022.0	0.0	0.0	2.1	0.0	0.0	100.0	39.9	0.0	0.0	4,789.8	614.4	0.0	20.0	0.0	0.0	0.0	7,786.4	0.0	20,984.0
2021	1,175.4	14,345.5	330.3	0.0	0.0	0.0	0.0	48.0	0.0	1.3	0.0	0.0	12,267.5	2,048.8	0.0	0.0	6.0	0.0	0.0	4,178.0	90.0	34,490.8
2022	2,650.3	8,412.3	1,533.8	0.0	0.0	0.0	1,000.0	28.0	0.0	20.0	0.0	0.0	9,412.3	1,578.3	0.0	0.0	0.0	0.0	0.0	2,249.7	0.0	26,884.7
2023	2,408.2	10,861.0	851.5	0.0	0.0	0.0	0.0	36.6	0.0	0.0	0.0	0.0	9,193.0	5,383.9	0.0	0.0	0.0	0.0	0.0	1,705.0	0.0	30,439.2
2024	577.0	4,522.5	646.0	0.0	0.0	0.0	0.0	12.0	1,594.0	0.0	0.0	0.0	3,778.5	1,034.5	0.0	0.0	0.0	0.0	0.0	4,047.4	0.0	16,211.9
2025	115.5	44.0	463.0	0.0	0.0	0.0	0.0	16.8	0.0	0.0	0.0	0.0	511.7	142.5	0.0	0.0	0.0	0.0	0.0	3,176.7	0.0	4,470.2
2026	40.0	575.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,177.1	32.5	0.0	0.0	0.0	0.0	0.0	885.2	0.0	2,709.8
2027	121.0	625.0	675.0	0.0	0.0	0.0	200.0	0.0	0.0	0.0	0.0	0.0	859.5	78.2	0.0	0.0	0.0	0.0	0.0	800.1	0.0	3,358.8
2028	124.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,005.0	210.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,339.0
2029	320.0	0.0	0.0	0.0	0.0	0.0	0.0	9.5	0.0	0.0	0.0	0.0	500.0	400.0	0.0	0.0	0.0	0.0	0.0	2,309.7	0.0	3,539.2
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	9,580.0	235,711.6	7,255.8	2,324.0	1,316.7	6.4	1,200.0	2,209.9	9,227.0	481.2	76.9	98.6	62,909.5	12,152.9	0.0	34,396.6	33.0	0.0	1,088.0	92,692.9	106.3	472,867.2

Completion Rates

The probability of a project going into service increases as each step of the serial planning process is completed. Table 12-28 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 any milestone completed beyond the FSA including a Construction Service Agreement (CSA), Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement (UCSA) and Wholesale Market Participant Agreement (WMPA) as well as the historic completion rates for all projects including those withdrawn before reaching the SIS milestone.[68] For each unit type, the total MW in service was divided by the total energy MW entered in the serial 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 battery projects to ever enter the serial queue and complete the system impact study stage, 6.3 percent of the queued MW have gone into service. The completion rate for battery projects increases to 15.4 percent when battery projects complete the facility study agreement and further increases to 36.3 percent when battery projects complete the construction service agreement. Of all battery projects to enter the serial queue, only 3.0 percent of the queued MW have gone into service.

68 All milestones after the FSA are included in the totals under the CSA headings of the tables within Section 12, "Generation and Transmission Planning."

Table 12-28 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: December 31, 2025

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)	Completion Rate (ALL)
Battery	6.3%	15.4%	36.3%	3.0%
CC	33.9%	49.6%	71.4%	16.9%
CT - Natural Gas	59.3%	70.4%	72.1%	50.0%
CT - Oil	35.7%	60.0%	90.9%	25.4%
CT - Other	12.1%	18.4%	29.5%	10.6%
Fuel Cell	50.6%	51.8%	51.8%	41.4%
Hydro - Pumped Storage	35.8%	35.8%	66.1%	24.5%
Hydro - Run of River	40.2%	55.5%	61.5%	20.7%
Nuclear	34.3%	41.4%	51.3%	28.2%
RICE - Natural Gas	32.4%	44.7%	49.4%	28.0%
RICE - Oil	34.0%	59.7%	59.7%	26.2%
RICE - Other	88.9%	91.3%	92.0%	77.9%
Solar	29.1%	46.5%	63.4%	14.4%
Solar + Storage	0.4%	1.0%	2.9%	0.2%
Solar + Wind	0.0%	0.0%	0.0%	0.0%
Steam - Coal	13.8%	25.7%	37.9%	6.4%
Steam - Natural Gas	90.5%	91.1%	91.1%	90.5%
Steam - Oil	0.0%	0.0%	0.0%	0.0%
Steam - Other	31.0%	40.6%	48.6%	28.0%
Wind	16.8%	32.6%	49.9%	10.3%
Wind + Storage	45.3%	45.3%	45.3%	45.3%

On December 31, 2025, 41,528.9 MW were in generation request serial queues in the status of active, under construction or suspended. Of the total 41,528.9 MW in the queue, 30,081.4 MW (72.4 percent) have reached the CSA milestone and 11,447.5 MW (27.6 percent) have not received a completed CSA. Based on historical completion rates, (applying the unit type specific completion rates for those projects that have reached the SIS, FSA or any milestone beyond the FSA, and using the overall completion rates for those projects that have not yet reached the SIS milestone), 22,140.7 MW (53.3 percent) of new generation in the serial queue are expected to go into service.

Table 12-29 shows the percent of all project MW, by unit type, to go in service by year submitted to the serial queue. Of all battery projects that entered the serial queue in 2010, 65.5 percent reached the status of in service by December 31, 2025. Of all battery projects that entered the serial queue in 2016, only 1.3 percent have reached the status of in service as of December 31, 2025.

Table 12-29 Percent of all projects (MW energy) to go in service by unit type and year submitted to the serial queue: December 31, 2025

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Battery	65.5%	8.3%	15.1%	45.7%	21.5%	11.5%	1.3%	0.0%	3.1%	0.5%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%
CC	14.6%	24.5%	30.8%	35.6%	53.6%	13.4%	20.7%	8.1%	4.1%	2.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CT - Natural Gas	100.0%	98.3%	71.6%	42.2%	56.8%	0.2%	13.2%	38.9%	8.4%	5.4%	7.2%	0.0%	0.0%	0.0%	0.0%	0.0%
CT - Oil	100.0%	NA	1.2%	0.0%	0.0%	NA	NA	NA	0.0%	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CT - Other	28.8%	26.2%	36.1%	100.0%	1.3%	100.0%	NA	0.0%	NA	NA	NA	0.0%	0.0%	0.0%	0.0%	0.0%
Fuel Cell	NA	NA	NA	NA	NA	67.4%	0.0%	0.0%	NA	100.0%	NA	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro - Pumped Storage	NA	NA	NA	NA	NA	100.0%	NA	NA	0.0%	0.0%	NA	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro - Run of River	0.0%	0.0%	57.6%	49.6%	11.2%	NA	100.0%	26.8%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	15.5%	1.6%	0.0%	100.0%	NA	NA	25.4%	100.0%	100.0%	NA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
RICE - Natural Gas	NA	NA	100.0%	66.7%	5.4%	6.2%	0.0%	5.4%	NA	100.0%	NA	0.0%	0.0%	0.0%	0.0%	0.0%
RICE - Oil	0.0%	0.0%	NA	NA	NA	30.8%	NA	NA	NA	NA	NA	0.0%	0.0%	0.0%	0.0%	0.0%
RICE - Other	100.0%	100.0%	100.0%	100.0%	79.7%	25.5%	2.8%	0.0%	100.0%	NA	NA	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	10.7%	8.1%	16.9%	24.4%	38.8%	30.5%	39.5%	15.6%	7.1%	11.6%	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar + Storage	NA	NA	NA	NA	NA	100.0%	0.7%	0.0%	0.0%	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar + Wind	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	100.0%	0.0%	1.4%	68.4%	1.2%	23.4%	37.5%	100.0%	59.2%	100.0%	NA	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Natural Gas	NA	NA	NA	100.0%	0.0%	100.0%	100.0%	100.0%	NA	NA	45.5%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Oil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Other	0.5%	61.2%	16.6%	0.0%	0.0%	NA	NA	NA	NA	NA	NA	0.0%	0.0%	0.0%	0.0%	0.0%
WInd	6.1%	3.4%	2.5%	20.9%	20.7%	12.5%	26.8%	2.6%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind + Storage	NA	NA	NA	NA	NA	NA	0.0%	0.0%	NA	NA	NA	0.0%	0.0%	0.0%	0.0%	0.0%
All	11.6%	19.0%	25.9%	35.9%	43.0%	15.8%	27.2%	11.9%	4.2%	7.0%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%

Table 12-30 shows the total MW that went in service each year, by unit type, since 1999. In 2025, 2,492.7 MW from the serial queue went in service. Of the 2,492.7 MW that went in service, 2,208.8 MW (88.6 percent) were solar units, 254.9 MW (10.2 percent) were wind units and 29.0 MW (1.2 percent) were coal fired steam units.

Table 12-30 Total (MW Energy) by unit type and year project went in service: December 31, 2025

Unit Type	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Battery	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.4	4.5	23.0	24.0	110.4	10.0	2.0	40.0	25.5	0.0	1.5	0.0	61.8	42.5	0.0
CC	0.0	0.0	100.0	2,608.0	2,785.0	2,845.0	15.1	1,196.0	4.0	177.0	52.0	136.0	1,869.0	162.7	82.2	2,155.7	2,977.7	5,418.0	3,888.1	10,865.0	2,983.0	88.0	3,424.7	1,825.9	2,644.0	0.0	0.0
CT - Natural Gas	0.0	409.6	432.0	2,442.0	638.7	61.3	993.0	39.3	97.0	821.0	181.7	97.8	850.4	393.0	95.0	125.2	317.9	72.0	212.0	388.0	104.0	156.0	314.0	151.6	532.1	0.0	0.0
CT - Oil	4.0	0.0	315.0	6.5	0.0	33.0	292.0	7.5	21.0	15.3	85.6	0.0	23.9	2.0	0.5	2.0	0.0	0.0	0.0	0.0	0.0	13.0	0.0	0.0	0.0	0.0	0.0
CT - Other	0.0	0.0	10.0	0.0	0.0	4.1	0.0	0.0	11.0	6.9	0.0	18.2	0.0	70.7	17.6	6.0	8.1	5.9	0.0	0.0	3.2	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cell	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.5	0.0	3.0	0.0	0.0	0.0	0.0	0.0
Hydro - Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	340.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro - Run of River	0.0	0.0	0.0	107.0	196.0	2.0	0.0	5.7	2.5	0.0	54.2	180.0	27.0	0.0	6.0	28.9	160.5	0.0	29.5	5.5	0.0	2.4	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	165.0	15.0	44.0	0.0	1,693.0	242.0	130.0	115.0	0.0	281.0	422.0	328.0	117.0	80.0	54.0	133.8	130.0	0.0	0.0	0.0	0.0	0.0	54.2	0.0	0.0
RICE - Natural Gas	0.0	0.0	0.0	0.0	0.0	8.0	29.0	2.0	19.5	0.0	0.0	10.5	0.0	0.0	0.0	0.0	18.9	20.9	19.9	5.2	39.8	0.0	14.4	0.0	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0	0.0	0.0	23.3	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	4.0	0.0	0.0	0.0	0.0	0.0
RICE - Other	0.0	1.2	0.0	2.9	17.2	0.0	27.5	44.9	86.6	57.6	38.8	13.8	39.8	2.0	109.0	0.0	3.8	19.3	22.4	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0
Solar	80.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	5.1	6.8	137.2	98.9	44.4	59.8	172.1	290.8	450.9	284.5	555.6	1,670.8	807.5	1,078.5	1,283.9	4,451.0	2,208.8
Solar + Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0	1.0	2.0	1.1	0.0	3.2	0.0	17.0	0.0	0.0
Solar + Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Steam - Coal	12.0	20.0	59.0	21.0	0.0	37.0	20.0	14.0	55.0	720.5	123.0	177.0	97.0	708.0	48.0	16.0	92.5	0.0	47.0	24.0	20.0	0.0	11.0	0.0	0.0	0.0	29.0
Steam - Natural Gas	0.0	0.0	2.5	10.0	0.0	0.0	0.0	0.0	25.0	145.0	0.0	0.0	5.5	0.0	0.0	0.0	0.0	696.5	0.0	0.0	0.0	64.0	0.0	0.0	0.0	5.0	0.0
Steam - Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	529.0	18.0	20.0	0.0	122.5	0.9	0.0	50.0	3.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WInd	0.0	0.0	0.0	15.0	190.0	20.4	7.5	380.0	867.3	725.2	622.0	1,183.5	273.6	1,423.1	150.0	500.0	455.0	465.8	700.7	762.0	535.0	1,008.4	310.0	0.0	282.4	289.8	254.9
Wind + Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	186.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	100.0	430.8	1,083.5	5,227.4	3,870.9	3,034.1	3,077.1	2,460.4	1,522.9	2,806.8	1,502.4	2,243.1	3,773.6	3,192.8	742.7	3,001.4	4,371.9	7,133.0	5,503.5	12,411.7	4,268.0	3,009.6	4,886.2	3,056.0	4,875.4	4,788.3	2,492.7

Analysis by Fuel Group

The time it takes to complete a study depends on the backlog and the number of projects in the serial queue, but not on the size of the project. Table 12-31 shows the number of projects that entered the serial queue by year and by fuel group. The fuel groups are nuclear units, renewable units (including hydro run of river, solar and wind units (including renewable solar and wind hybrids), storage units (including battery and pumped storage hydro units), thermal units (including combined cycle, CT natural gas and oil, RICE natural gas and oil and steam coal, natural gas and oil) and other units (all other fuels). Of the 2,809 projects entered from January 2015 through June 2023, 2,062 projects (73.4 percent) were renewable.

Table 12-31 Number of projects entered in the serial queue by fuel group: December 31, 2025

	Fuel Group										
Year Entered	Nuclear	Percent Nuclear	Renewable	Percent Renewable	Storage	Percent Storage	Thermal	Percent Thermal	Other	Percent Other	Total
1997	2	15.38%	0	0.00%	0	0.00%	11	84.62%	0	0.00%	13
1998	0	0.00%	0	0.00%	0	0.00%	18	100.00%	0	0.00%	18
1999	1	1.11%	5	5.56%	0	0.00%	82	91.11%	2	2.22%	90
2000	2	2.41%	3	3.61%	0	0.00%	75	90.36%	3	3.61%	83
2001	4	4.40%	6	6.59%	0	0.00%	78	85.71%	3	3.30%	91
2002	3	5.88%	15	29.41%	0	0.00%	23	45.10%	10	19.61%	51
2003	1	1.89%	34	64.15%	0	0.00%	13	24.53%	5	9.43%	53
2004	4	7.41%	17	31.48%	0	0.00%	23	42.59%	10	18.52%	54
2005	3	2.26%	74	55.64%	1	0.75%	36	27.07%	19	14.29%	133
2006	9	5.73%	67	42.68%	0	0.00%	47	29.94%	34	21.66%	157
2007	9	4.11%	64	29.22%	1	0.46%	123	56.16%	22	10.05%	219
2008	3	1.39%	102	47.22%	7	3.24%	79	36.57%	25	11.57%	216
2009	10	5.78%	107	61.85%	2	1.16%	34	19.65%	20	11.56%	173
2010	5	1.13%	370	83.90%	5	1.13%	40	9.07%	21	4.76%	441
2011	6	1.69%	264	74.37%	4	1.13%	61	17.18%	20	5.63%	355
2012	2	1.26%	59	37.11%	11	6.92%	69	43.40%	18	11.32%	159
2013	1	0.65%	54	35.06%	21	13.64%	69	44.81%	9	5.84%	154
2014	0	0.00%	100	52.08%	21	10.94%	59	30.73%	12	6.25%	192
2015	0	0.00%	130	42.07%	63	20.39%	103	33.33%	13	4.21%	309
2016	2	0.50%	284	71.18%	22	5.51%	65	16.29%	26	6.52%	399
2017	2	0.56%	280	78.87%	7	1.97%	47	13.24%	19	5.35%	355
2018	1	0.23%	336	77.42%	50	11.52%	46	10.60%	1	0.23%	434
2019	0	0.00%	487	78.30%	85	13.67%	49	7.88%	1	0.16%	622
2020	2	0.29%	545	78.99%	122	17.68%	21	3.04%	0	0.00%	690
2021	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0
2022	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0
2023	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0
Total	72	1.32%	3,403	62.31%	422	7.73%	1,271	23.27%	293	5.37%	5,461

As of December 31, 2025, renewable projects make up 85.7 percent of all projects in the serial queue and those projects account for 79.6 percent of the nameplate MW currently active, suspended or under construction.

Table 12-32 Serial queue details by fuel group: December 31, 2025

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	1	0.2%	44.0	0.1%
Renewable	373	85.7%	33,066.3	79.6%
Storage	44	10.1%	3,106.1	7.5%
Thermal	17	3.9%	5,312.5	12.8%
Other	0	0.0%	0.0	0.0%
Total	435	100.0%	41,528.9	100.0%

Historical completion rates for renewable projects may not be an accurate predictor of completion rates for current renewable projects. The outcomes for current projects will provide additional information and improve the ability to assess the likely future generation mix based on the type of projects in the queue.

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 was operational data to support a different conclusion.[69] 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 were dependent on the wind farm locations and had an average derate of 16.2 percent. The capacity factor derates for solar resources were dependent on the solar installation type and had an average derate of 46.7 percent.

Beginning with the 2023/2024 Delivery Year, unforced capacity for intermittent resources and limited duration resources are determined by PJM's effective load carrying capability (ELCC) analysis. The PJM ELCC analysis determines capacity derates by resource class for each Delivery Year. The unforced capacity derate for a specific resource will equal the product of the ELCC class rating and a resource specific performance factor. For example, the 2027/2028 Base Residual Auction ELCC class rating for onshore wind resources is 41.0 percent, for solar resources with tracking panels is 8.0 percent and for solar resources with fixed panels is 7.0 percent.[70] The ELCC class rating for battery or storage resources replaces the 10 hour rule that was previously used to determine the unforced capacity value for a storage resource. PJM defined four different storage classes differentiated by duration. The ELCC class rating is 58.0 percent for storage resources that can continuously generate energy at the nameplate capacity for four hours (four hour storage). The ELCC class rating is 67.0 percent for six hour storage and 70.0 percent for eight hour storage and 78.0 percent for 10 hour storage.[71]

While renewables currently make up the majority of both projects and nameplate MW in the serial queue, historical completion rates and derating factors must be accounted for when evaluating the share of capacity resources that are likely to be contributed by renewables. Table 12-33 shows the total MW of all projects in the serial queue as of December 31, 2025, in the status of active, suspended and under construction, by unit type. Table 12-33 also shows the total MW Energy and MW Capacity for each fuel type adjusted based on current historical completion rates and, for Capacity MW in the queue, adjusted for ELCC derates.[72]

Table 12-33 shows that of the 5,312.5 MW, on an energy basis, of thermal projects (including combined cycle, CT natural gas and coal fired steam projects) in the serial queue, 3,770.5 MW (71.0 percent) are expected to go in service based on historical completion rates as of December 31, 2025.

Of the 3,106.1 MW, on an energy basis, of battery projects in the serial queue, 816.7 MW (26.3 percent) are expected to go in service based on historical completion rates as of December 31, 2025.

Of the 33,066.3 MW, on an energy basis, of renewable projects in the serial queue, 17,530.9 MW (53.0 percent) are expected to go in service based on historical completion rates as of December 31, 2025.

Of the 3,949.1 MW, on a capacity basis that requested CIRs, of combined cycle projects requested in the generation serial queues in the status of active, under

69 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 58 (December 17, 2025).

70 Unless otherwise noted, the ELCC derate factors in this section are based on the *ELCC Class Ratings for 2027/2028 Base Residual Auction*, PJM Interconnection L.L.C. (August 1, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2027-28-bra-elcc-class-ratings.pdf>.

71 Additional information available in *PJM Manual 21A: Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis*, PJM Interconnection L.L.C., Rev. 5 (June 27, 2024).

72 Unless otherwise noted, the ELCC derate adjusted MW are calculated using the 2027/2028 Base Residual Auction ELCC factors. The adjusted MW are calculated using the four hour storage ELCC derate of 58.0 percent for battery resources, 41.0 percent ELCC derate for wind resources and 8.0 percent ELCC derate for solar resources.

construction or suspended, 2,777.1 MW (70.3 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 3,949.1 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 2,055.1 MW of capacity (52.0 percent of the total requested capacity).

Of the 5,140.6 MW, on a capacity basis that requested CIRs, of thermal projects (including combined cycle, CT natural gas and coal fired steam projects) requested in the generation serial queues in the status of active, under construction or suspended, 3,585.9 MW (69.8 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction,[73] the 5,140.6 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 2,551.4 MW of capacity (49.6 percent of the total requested capacity).

Of the 2,098.3 MW, on a capacity basis that requested CIRs, of battery projects requested in the generation serial queues in the status of active, under construction or suspended, 143.9 MW (6.9 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 2,098.3 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 83.5 MW of capacity (4.0 percent of the total requested capacity).

Of the 17,088.7 MW, on a capacity basis that requested CIRs, of renewable projects requested in the generation serial queues in the status of active, under construction or suspended, 9,061.2 MW (53.0 percent) are expected to go into service based on historical completion rates. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 17,088.7 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 903.0 MW of capacity (5.3 percent of the total requested capacity).

As of December 31, 2025, 24,371.6 MW of capacity requests (requested CIRs) were in the generation serial queues in the status of active, under construction or suspended. Based on historical completion rates, 12,813.1 MW (52.6 percent) are expected to go into service. Based on historical completion rates and the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction, the 24,371.6 MW of capacity requests currently under construction, suspended or active in the serial queue would be reduced to 3,558.9 MW of capacity (14.6 percent of the total requested capacity).

73 Unless otherwise noted, the ELCC derate factors in this section are based on the *ELCC Class Ratings for 2027/2028 Base Residual Auction*, PJM Interconnection L.L.C. (August 1, 2025) <https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2027-28-bra-elcc-class-ratings.pdf>.

Table 12-33 Serial queue totals for projects (active, suspended and under construction) by unit type adjusted for current historical completion rates and ELCC derates (MW): December 31, 2025

	Energy (MW)		Capacity (MW)		
Unit Type	Total	Completion Rate Adjusted	Total	Completion Rate Adjusted	Completion Rate and ELCC Adjusted
Battery	3,106.1	816.7	2,098.3	143.9	83.5
CC	4,158.8	2,958.5	3,949.1	2,777.1	2,055.1
CT - Natural Gas	1,117.7	798.4	1,155.5	795.1	485.0
CT - Oil	0.0	0.0	0.0	0.0	0.0
CT - Other	0.0	0.0	0.0	0.0	0.0
Fuel Cell	0.0	0.0	0.0	0.0	0.0
Hydro - Pumped Storage	0.0	0.0	0.0	0.0	0.0
Hydro - Run of River	51.0	28.3	30.0	17.2	6.7
Nuclear	44.0	22.6	44.0	22.1	21.0
RICE - Natural Gas	0.0	0.0	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0	0.0	0.0
Solar	25,586.5	14,841.6	14,525.5	8,497.1	679.8
Solar + Storage	2,079.2	39.2	1,482.2	23.4	1.9
Solar + Wind	0.0	0.0	0.0	0.0	0.0
Steam - Coal	36.0	13.6	36.0	13.7	11.4
Steam - Natural Gas	0.0	0.0	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0	0.0	0.0
Wind	5,349.7	2,621.7	1,050.9	523.5	214.6
Wind + Storage	0.0	0.0	0.0	0.0	0.0
Total	41,528.9	22,140.7	24,371.6	12,813.1	3,558.9

Analysis by Unit Type and Project Classification

Table 12-34 shows the status of all generation serial queue projects by unit type and project classification as of December 31, 2025. As of December 31, 2025, 5,461 projects, representing 609,262.3 MW, have entered the serial queue process from 1997 until the implementation of the new cycle process on July 10, 2023. Of those, 1,276 projects, representing 94,866.2 MW (15.6 percent of the MW), went into service. Of the projects that entered the serial queue process, 3,750 projects, representing 472,867.2 MW (77.6 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 4,353 projects have been classified as new generation and 1,108 projects have been classified as upgrades. Natural gas, wind, solar and renewable hybrid projects (including solar + storage, solar + wind and wind + storage) have accounted for 4,361 projects (79.9 percent) of all 5,461 generation serial queue projects to enter the queue since January 1, 1997.

Table 12-34 Status of all generation serial queue projects: December 31, 2025

		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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	31	67	50	10	25	2	0	10	2	11	0	55	313	6	0	8	6	0	4	100	1	701
	Upgrade	9	117	137	25	5	1	3	19	45	9	2	16	88	1	0	59	10	0	8	20	1	575
Under Construction	New Generation	4	2	0	0	0	0	0	0	0	0	0	0	61	4	0	0	0	0	0	7	0	78
	Upgrade	1	2	1	0	0	0	0	0	1	0	0	0	14	1	0	1	0	0	0	2	0	23
Suspended	New Generation	8	1	0	0	0	0	0	0	0	0	0	0	76	1	0	0	0	0	0	7	0	93
	Upgrade	3	0	0	0	0	0	0	0	0	0	0	0	18	0	0	0	0	0	0	2	0	23
Withdrawn	New Generation	239	440	32	10	82	28	4	48	9	29	12	16	1,636	152	0	55	1	0	34	487	1	3,315
	Upgrade	92	107	25	13	12	0	0	4	15	0	2	3	106	5	0	15	2	0	2	31	1	435
Active	New Generation	20	3	1	0	0	0	0	0	0	0	0	0	117	19	0	0	0	0	0	6	0	166
	Upgrade	8	1	5	0	0	0	0	1	0	0	0	0	34	1	0	0	0	0	0	2	0	52
Total Projects	New Generation	302	513	83	20	107	30	4	58	11	40	12	71	2,203	182	0	63	7	0	38	607	2	4,353
	Upgrade	113	227	168	38	17	1	3	24	61	9	4	19	260	8	0	75	12	0	10	57	2	1,108

Table 12-35 shows the totals in Table 12-34 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, 73.8 percent of all hydro run of river projects classified as upgrades are currently in service in PJM, 17.6 percent of hydro run of river upgrades were withdrawn and 8.6 percent of hydro run of river upgrades are active in the serial queue.

Table 12-35 Status of all generation serial queue projects as a percent of total projects by classification: December 31, 2025

		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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	10.3%	13.1%	60.2%	50.0%	23.4%	6.7%	0.0%	17.2%	18.2%	27.5%	0.0%	77.5%	14.2%	3.3%	0.0%	12.7%	85.7%	0.0%	10.5%	16.5%	50.0%	16.1%
	Upgrade	8.0%	51.5%	81.5%	65.8%	29.4%	100.0%	100.0%	79.2%	73.8%	100.0%	50.0%	84.2%	33.8%	12.5%	0.0%	78.7%	83.3%	0.0%	80.0%	35.1%	50.0%	51.9%
Under Construction	New Generation	1.3%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.8%	2.2%	0.0%	0.0%	0.0%	0.0%	0.0%	1.2%	0.0%	1.8%
	Upgrade	0.9%	0.9%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%	5.4%	12.5%	0.0%	1.3%	0.0%	0.0%	0.0%	3.5%	0.0%	2.1%
Suspended	New Generation	2.6%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.4%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	1.2%	0.0%	2.1%
	Upgrade	2.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.5%	0.0%	2.1%
Withdrawn	New Generation	79.1%	85.8%	38.6%	50.0%	76.6%	93.3%	100.0%	82.8%	81.8%	72.5%	100.0%	22.5%	74.3%	83.5%	0.0%	87.3%	14.3%	0.0%	89.5%	80.2%	50.0%	76.2%
	Upgrade	81.4%	47.1%	14.9%	34.2%	70.6%	0.0%	0.0%	16.7%	24.6%	0.0%	50.0%	15.8%	40.8%	62.5%	0.0%	20.0%	16.7%	0.0%	20.0%	54.4%	50.0%	39.3%
Active	New Generation	6.6%	0.6%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.3%	10.4%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	0.0%	3.8%
	Upgrade	7.1%	0.4%	3.0%	0.0%	0.0%	0.0%	0.0%	4.2%	0.0%	0.0%	0.0%	0.0%	13.1%	12.5%	0.0%	0.0%	0.0%	0.0%	0.0%	3.5%	0.0%	4.7%

Table 12-36 shows the total MW of projects in the PJM generation status queue by unit type and project classification. For example, the 487 new generation wind projects that have been withdrawn from the serial queue as of December 31, 2025, (as shown in Table 12-34) constitute 90,541.2 MW. The 440 new generation combined cycle projects that have been withdrawn in the same time period constitute 221,887.8 MW.

Table 12-36 Status of all generation (MW) in the generation serial queue: December 31, 2025

		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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	296.8	39,701.9	6,734.4	676.5	149.2	1.5	0.0	371.5	1,639.0	170.8	0.0	440.1	12,125.3	22.1	0.0	1,343.0	728.0	0.0	60.9	10,829.1	186.0	75,476.1
	Upgrade	79.8	8,600.1	3,190.2	144.8	12.4	3.0	390.0	435.6	2,365.0	17.3	27.3	47.5	1,564.6	3.2	0.0	1,008.0	225.5	0.0	683.3	592.5	0.0	19,390.1
Under Construction	New Generation	355.7	1,515.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,939.2	61.6	0.0	0.0	0.0	0.0	0.0	1,608.4	0.0	10,479.9
	Upgrade	50.0	153.8	60.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	392.2	100.0	0.0	36.0	0.0	0.0	0.0	118.5	0.0	954.5
Suspended	New Generation	536.0	1,270.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,355.6	150.0	0.0	0.0	0.0	0.0	0.0	1,954.5	0.0	9,266.1
	Upgrade	102.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	413.5	0.0	0.0	0.0	0.0	0.0	0.0	107.3	0.0	623.0
Withdrawn	New Generation	7,383.0	221,887.8	5,794.3	1,735.0	1,248.0	6.4	1,200.0	2,105.9	8,161.0	481.2	63.9	88.6	59,924.3	11,709.2	0.0	33,511.6	27.0	0.0	1,050.9	90,541.2	90.0	447,009.2
	Upgrade	2,196.9	13,823.9	1,461.5	589.0	68.7	0.0	0.0	104.0	1,066.0	0.0	13.0	10.0	2,985.2	443.7	0.0	885.0	6.0	0.0	37.1	2,151.8	16.3	25,858.0
Active	New Generation	1,740.0	1,175.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10,495.7	1,673.6	0.0	0.0	0.0	0.0	0.0	1,411.0	0.0	17,064.2
	Upgrade	322.2	45.0	488.7	0.0	0.0	0.0	0.0	51.0	0.0	0.0	0.0	0.0	1,990.3	94.0	0.0	0.0	0.0	0.0	0.0	150.0	0.0	3,141.2
Total Projects	New Generation	10,311.5	265,549.7	13,097.7	2,411.5	1,397.2	7.9	1,200.0	2,477.4	9,800.0	652.0	63.9	528.7	94,840.1	13,616.4	0.0	34,854.6	755.0	0.0	1,111.8	106,344.1	276.0	559,295.5
	Upgrade	2,751.1	22,622.8	5,200.4	733.8	81.1	3.0	390.0	590.6	3,475.0	17.3	40.3	57.5	7,345.8	640.9	0.0	1,929.0	231.5	0.0	720.4	3,120.1	16.3	49,966.9

Table 12-37 shows the MW totals in Table 12-36 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, 85.1 percent of wind project MW classified as new generation have been withdrawn from the serial queue between January 1, 1997, and December 31, 2025.

Table 12-37 Status of all generation serial queue projects as percent of total MW in project classification: December 31, 2025

		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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	2.9%	15.0%	51.4%	28.1%	10.7%	19.2%	0.0%	15.0%	16.7%	26.2%	0.0%	83.2%	12.8%	0.2%	0.0%	3.9%	96.4%	0.0%	5.5%	10.2%	67.4%	13.5%
	Upgrade	2.9%	38.0%	61.3%	19.7%	15.3%	100.0%	100.0%	73.8%	68.1%	100.0%	67.7%	82.6%	21.3%	0.5%	0.0%	52.3%	97.4%	0.0%	94.9%	19.0%	0.0%	38.8%
Under Construction	New Generation	3.4%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.3%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%	0.0%	1.9%
	Upgrade	1.8%	0.7%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	5.3%	15.6%	0.0%	1.9%	0.0%	0.0%	0.0%	3.8%	0.0%	1.9%
Suspended	New Generation	5.2%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.6%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	0.0%	1.7%
	Upgrade	3.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.4%	0.0%	1.2%
Withdrawn	New Generation	71.6%	83.6%	44.2%	71.9%	89.3%	80.8%	100.0%	85.0%	83.3%	73.8%	100.0%	16.8%	63.2%	86.0%	0.0%	96.1%	3.6%	0.0%	94.5%	85.1%	32.6%	79.9%
	Upgrade	79.9%	61.1%	28.1%	80.3%	84.7%	0.0%	0.0%	17.6%	30.7%	0.0%	32.3%	17.4%	40.6%	69.2%	0.0%	45.9%	2.6%	0.0%	5.1%	69.0%	100.0%	51.8%
Active	New Generation	16.9%	0.4%	4.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	11.1%	12.3%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	3.1%
	Upgrade	11.7%	0.2%	9.4%	0.0%	0.0%	0.0%	0.0%	8.6%	0.0%	0.0%	0.0%	0.0%	27.1%	14.7%	0.0%	0.0%	0.0%	0.0%	0.0%	4.8%	0.0%	6.3%

Table 12-38 shows the project MW that entered the PJM generation serial queue by unit type and year of entry. Since 2016, 82.5 percent of all new projects entering the generation serial queue have been combined cycle (19.6 percent), wind (17.2 percent) or solar projects (45.7 percent). Prior to 2015, no renewable hybrid units (solar + storage, solar + wind and wind + storage) entered the queue. In the time period from January 1, 2015 through June 10, 2023, 14,549.6 MW of renewable hybrid units have entered the serial queue.

Table 12-38 Serial queue project MW by unit type and queue entry year: December 31, 2025

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	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	0.0	0.0	6.0	0.0	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	0.0	0.0	0.0	8,781.0
1999	0.0	29,412.7	2,069.1	0.0	10.0	0.0	0.0	196.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	47.0	0.0	0.0	525.0	115.4	0.0	32,420.2
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	0.0	0.0	37.0	2.5	0.0	0.0	95.6	0.0	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	0.0	0.0	1,244.6	10.0	0.0	0.0	234.9	0.0	27,377.8
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	0.0	0.0	1,895.0	0.0	0.0	0.0	790.9	0.0	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	0.0	0.0	522.0	0.0	0.0	165.0	997.0	0.0	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	0.0	0.0	1,187.0	0.0	0.0	0.0	1,428.7	186.0	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	0.0	0.0	6,360.0	0.0	0.0	24.0	6,015.4	0.0	20,360.3
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	0.0	0.0	9,586.0	0.0	0.0	258.5	7,596.3	0.0	29,909.8
2007	0.0	13,926.6	941.2	215.9	149.5	0.0	16.0	209.6	368.0	0.0	0.0	56.5	3.3	0.0	0.0	9,078.0	190.0	0.0	68.5	18,510.5	0.0	43,733.5
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	0.0	0.0	1,200.5	0.0	0.0	189.8	10,955.3	0.0	41,662.9
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	0.0	0.0	1,273.0	5.5	0.0	148.0	6,672.6	0.0	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	54.6	3,671.4	0.0	0.0	64.0	0.0	0.0	173.5	9,803.4	0.0	23,886.9
2011	24.1	19,744.0	29.5	0.0	172.5	0.0	0.0	30.0	182.0	0.0	14.0	75.3	2,014.0	0.0	0.0	357.0	0.0	0.0	49.0	5,576.4	0.0	28,267.8
2012	142.6	18,014.8	102.1	42.5	48.4	0.0	0.0	11.8	369.0	37.2	0.0	4.0	284.6	0.0	0.0	1,837.0	0.0	0.0	143.1	1,529.8	0.0	22,566.8
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	0.0	0.0	158.0	40.0	0.0	44.7	1,296.6	0.0	13,952.1
2014	246.9	11,704.5	1,532.5	401.0	7.8	0.0	0.0	60.5	0.0	48.0	0.0	17.7	1,553.6	0.0	0.0	1,730.5	27.0	0.0	43.1	1,691.3	0.0	19,064.4
2015	546.9	27,550.8	1,324.5	0.0	0.9	2.3	34.0	0.0	0.0	320.4	13.0	31.4	2,919.3	3.4	0.0	47.0	606.5	0.0	0.0	2,160.6	0.0	35,560.9
2016	111.1	18,802.5	1,392.0	0.0	0.0	2.9	0.0	12.5	59.0	23.5	0.0	38.9	11,538.9	85.6	0.0	80.0	77.0	0.0	0.0	3,445.7	16.3	35,685.9
2017	24.6	5,477.6	691.0	0.0	4.1	2.7	0.0	20.5	39.1	97.1	0.0	33.8	13,686.8	324.9	0.0	14.0	17.0	0.0	0.0	5,137.0	90.0	25,660.3
2018	1,413.7	11,080.1	2,510.5	14.0	0.0	0.0	700.0	2.4	28.1	0.0	0.0	0.8	19,895.6	3,907.9	0.0	49.0	0.0	0.0	0.0	17,278.3	0.0	56,880.4
2019	4,192.8	3,332.5	1,003.7	13.0	0.0	3.0	500.0	99.0	0.0	14.4	0.0	0.0	25,384.3	4,625.3	0.0	11.0	0.0	0.0	0.0	6,036.1	0.0	45,215.1
2020	5,915.1	50.0	846.6	4.0	0.0	0.0	0.0	80.2	100.0	0.0	0.0	0.0	20,299.4	5,310.2	0.0	0.0	11.0	0.0	0.0	2,096.4	0.0	34,713.0
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	13,062.6	288,172.5	18,298.1	3,145.3	1,478.3	10.9	1,590.0	3,068.0	13,275.0	669.3	104.2	586.2	102,185.9	14,257.3	0.0	36,783.6	986.5	0.0	1,832.2	109,464.2	292.3	609,262.3

Combined Cycle Project Analysis

Table 12-39 shows the status of all combined cycle projects by number of projects that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the nine combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, four projects (44.4 percent) are located in the APS Zone.

Table 12-39 Status of all combined cycle serial queue projects by zone (number of projects): December 31, 2025

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	1	7	0	3	4	2	3	0	2	0	7	2	0	7	4	0	5	2	4	9	5	0	67
	Upgrade	3	15	0	10	5	0	6	0	0	0	16	5	0	6	5	0	13	3	4	12	14	0	117
Under Construction	New Generation	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
	Upgrade	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	2
Suspended	New Generation	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	24	20	0	46	14	8	17	1	1	2	18	16	3	26	25	0	44	41	35	42	55	2	440
	Upgrade	7	10	0	11	4	0	4	0	1	0	11	6	0	8	7	0	3	7	5	8	15	0	107
Active	New Generation	0	1	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
	Upgrade	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Total Projects	New Generation	25	29	0	52	19	10	20	1	3	2	25	18	3	33	29	0	49	43	39	51	60	2	513
	Upgrade	10	25	0	22	9	0	11	0	1	0	27	11	0	14	12	0	16	10	9	20	30	0	227

Table 12-40 shows the status of all combined cycle projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 4,158.8 MW of combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 1,915.0 MW (46.0 percent) are located in the APS Zone.

Table 12-40 Status of all combined cycle serial queue projects by zone (MW): December 31, 2025

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	650.0	5,611.0	0.0	1,970.0	3,751.0	140.0	2,960.9	0.0	533.0	0.0	5,828.6	319.2	0.0	1,665.8	2,557.0	0.0	2,665.0	1,900.0	1,560.0	5,892.0	1,698.5	0.0	39,701.9
	Upgrade	229.0	1,300.0	0.0	959.7	344.0	0.0	642.6	0.0	0.0	0.0	1,035.0	102.0	0.0	110.0	188.9	0.0	1,075.5	112.3	228.6	1,426.6	845.9	0.0	8,600.1
Under Construction	New Generation	0.0	575.0	0.0	0.0	940.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,515.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	102.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	51.1	0.0	153.8
Suspended	New Generation	0.0	0.0	0.0	1,270.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,270.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	8,542.5	13,559.5	0.0	22,373.1	9,596.0	3,122.1	11,392.0	1,150.0	134.5	665.0	12,961.0	5,145.4	991.8	13,562.6	13,001.0	0.0	24,140.0	16,114.0	22,268.2	18,917.7	24,244.6	6.9	221,887.8
	Upgrade	156.9	1,031.0	0.0	1,368.0	636.0	0.0	1,735.0	0.0	36.0	0.0	780.4	1,410.0	0.0	413.0	1,742.0	0.0	240.0	1,125.6	229.1	703.0	2,217.9	0.0	13,823.9
Active	New Generation	0.0	575.0	0.0	600.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,175.0
	Upgrade	0.0	0.0	0.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.0
Total Projects	New Generation	9,192.5	20,320.5	0.0	26,213.1	14,287.0	3,262.1	14,352.9	1,150.0	667.5	665.0	18,789.6	5,464.6	991.8	15,228.4	15,558.0	0.0	26,805.0	18,014.0	23,828.2	24,809.7	25,943.1	6.9	265,549.7
	Upgrade	385.9	2,331.0	0.0	2,372.7	980.0	0.0	2,480.3	0.0	36.0	0.0	1,815.4	1,512.0	0.0	523.0	1,930.9	0.0	1,315.5	1,237.9	457.7	2,129.6	3,114.9	0.0	22,622.8

Of the nine combined cycle units in the serial queue as of December 31, 2025, in the status of active, under construction or suspended, no units had a projected in service date prior to January 1, 2025 and nine units, representing 4,158.8 MW had a projected in service date between January 1, 2025, and December 31, 2029.

Combustion Turbine – Natural Gas Project Analysis

Table 12-41 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997, through July 10, 2023, by zone. Of the seven combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, four projects (57.1 percent) are located in the ATSI Zone.

Table 12-41 Status of all combustion turbine – natural gas generation serial queue projects by zone (number of projects): December 31, 2025

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	5	0	0	6	0	3	1	0	0	1	3	6	0	2	1	0	2	5	2	4	9	0	50
	Upgrade	4	11	0	10	5	0	20	6	0	0	28	8	0	5	5	0	4	8	5	4	14	0	137
Under Construction	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
	Upgrade	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	2	6	0	0	0	2	1	1	0	0	4	0	1	1	0	0	1	6	0	1	6	0	32
	Upgrade	3	1	0	1	1	0	5	3	0	2	3	0	0	0	1	0	0	2	3	0	0	0	25
Active	New Generation	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	1	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
Total Projects	New Generation	7	6	0	6	0	5	2	1	0	1	8	6	1	3	1	0	3	11	2	5	15	0	83
	Upgrade	7	12	0	12	10	0	26	9	0	2	31	8	0	5	6	0	4	10	8	4	14	0	168

Table 12-42 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 1,117.7 MW of combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, 569.0 MW (50.9 percent) are located in the DOM Zone.

Table 12-42 Status of all combustion turbine – natural gas serial queue projects by zone (MW): December 31, 2025

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	360.7	0.0	0.0	1,184.0	0.0	23.0	190.0	0.0	0.0	205.0	1,081.0	1,140.0	0.0	520.0	10.0	0.0	559.0	379.9	5.0	150.9	925.9	0.0	6,734.4
	Upgrade	43.7	278.1	0.0	267.8	105.0	0.0	744.0	83.5	0.0	0.0	925.7	86.0	0.0	20.0	47.6	0.0	42.0	40.5	39.0	252.3	215.0	0.0	3,190.2
Under Construction	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	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	60.0	0.0	0.0	0.0	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
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	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	237.5	1,519.0	0.0	0.0	0.0	153.6	10.0	104.0	0.0	0.0	1,069.8	0.0	73.0	2.1	0.0	0.0	0.5	789.8	0.0	19.9	1,815.1	0.0	5,794.3
	Upgrade	165.5	6.0	0.0	4.0	25.0	0.0	686.2	124.0	0.0	18.5	57.0	0.0	0.0	0.0	0.0	0.0	0.0	327.0	48.3	0.0	0.0	0.0	1,461.5
Active	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	569.0
	Upgrade	0.0	0.0	0.0	30.0	458.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	488.7
Total Projects	New Generation	598.2	1,519.0	0.0	1,184.0	0.0	176.6	200.0	104.0	0.0	205.0	2,719.8	1,140.0	73.0	522.1	10.0	0.0	559.5	1,169.7	5.0	170.8	2,741.0	0.0	13,097.7
	Upgrade	209.2	284.1	0.0	301.8	588.7	0.0	1,490.2	207.5	0.0	18.5	982.7	86.0	0.0	20.0	47.6	0.0	42.0	367.5	87.3	252.3	215.0	0.0	5,200.4

Of the seven combustion turbine natural gas units in the serial queue as of December 31, 2025, in the status of active, under construction or suspended, no units had a projected in service date prior to January 1, 2025 and seven units, representing 1,117.7 MW had a projected in service date between January 1, 2025, and December 31, 2031.

Wind Project Analysis

Table 12-43 shows the status of all wind generation projects, by number of projects that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 26 wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM serial generation queue, 10 projects (38.5 percent) are located in the COMED Zone.

Table 12-43 Status of all wind generation serial queue projects by zone (number of projects): December 31, 2025

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	1	17	0	18	0	0	29	0	0	0	4	0	0	0	0	0	0	23	0	8	0	0	100
	Upgrade	0	2	0	3	0	0	9	0	0	0	0	0	0	0	0	0	0	6	0	0	0	0	20
Under Construction	New Generation	0	2	0	1	0	0	2	0	0	0	1	0	0	0	0	0	0	1	0	0	0	0	7
	Upgrade	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Suspended	New Generation	1	1	0	1	0	0	2	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	7
	Upgrade	0	1	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	2
Withdrawn	New Generation	23	120	0	46	10	0	116	15	0	0	22	14	1	6	0	0	0	63	0	50	1	0	487
	Upgrade	2	2	0	7	0	0	7	0	0	0	3	1	0	1	0	0	0	6	0	2	0	0	31
Active	New Generation	0	2	0	0	1	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6
	Upgrade	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Total Projects	New Generation	25	142	0	66	11	0	152	15	0	0	27	15	1	7	0	0	0	87	0	58	1	0	607
	Upgrade	2	6	0	10	0	0	19	0	0	0	3	2	0	1	0	0	0	12	0	2	0	0	57

Table 12-44 shows the status of all wind projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 5,349.7 MW of wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, 2,384.6 MW (44.6 percent) are located in the COMED Zone.

Table 12-44 Status of all wind generation serial queue projects by zone (MW): December 31, 2025

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	7.5	3,223.0	0.0	1,232.9	0.0	0.0	4,586.7	0.0	0.0	0.0	511.5	0.0	0.0	0.0	0.0	0.0	0.0	1,041.0	0.0	226.5	0.0	0.0	10,829.1
	Upgrade	0.0	268.4	0.0	5.0	0.0	0.0	213.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	105.9	0.0	0.0	0.0	0.0	592.5
Under Construction	New Generation	0.0	340.3	0.0	80.0	0.0	0.0	1,000.0	0.0	0.0	0.0	78.2	0.0	0.0	0.0	0.0	0.0	0.0	109.9	0.0	0.0	0.0	0.0	1,608.4
	Upgrade	0.0	12.6	0.0	0.0	0.0	0.0	105.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	118.5
Suspended	New Generation	432.0	100.0	0.0	80.0	0.0	0.0	278.7	0.0	0.0	0.0	0.0	247.8	0.0	816.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,954.5
	Upgrade	0.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	107.3
Withdrawn	New Generation	7,653.2	24,731.4	0.0	3,552.2	1,814.0	0.0	27,483.5	2,128.0	0.0	0.0	5,788.5	3,680.8	150.3	4,447.2	0.0	0.0	0.0	5,257.0	0.0	3,835.2	20.0	0.0	90,541.2
	Upgrade	5.0	370.0	0.0	119.4	0.0	0.0	754.0	0.0	0.0	0.0	114.0	30.0	0.0	510.0	0.0	0.0	0.0	243.4	0.0	6.0	0.0	0.0	2,151.8
Active	New Generation	0.0	263.3	0.0	0.0	297.7	0.0	850.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,411.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	150.0
Total Projects	New Generation	8,092.7	28,658.0	0.0	4,945.1	2,111.7	0.0	34,198.9	2,128.0	0.0	0.0	6,378.2	3,928.6	150.3	5,263.2	0.0	0.0	0.0	6,407.9	0.0	4,061.7	20.0	0.0	106,344.1
	Upgrade	5.0	751.0	0.0	124.4	0.0	0.0	1,223.1	0.0	0.0	0.0	114.0	37.3	0.0	510.0	0.0	0.0	0.0	349.3	0.0	6.0	0.0	0.0	3,120.1

Of the 26 wind units in the serial queue as of December 31, 2025, in the status of active, under construction or suspended, two units, representing 160.0 MW had a projected in service date prior to January 1, 2025 and 24 units, representing 5,189.7 MW had a projected in service date between January 1, 2025, and December 31, 2029.

A total of 48 offshore wind projects entered PJM generation serial queues from January 1, 1997, through July 10, 2023. Offshore wind projects are included in the wind generation statistics. Of the 26 wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue (Table 12-43), four projects (15.4 percent) are offshore wind. Of the 5,349.7 MW of wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue (Table 12-44), 1,503.1 MW (28.1 percent) are offshore wind projects. Table 12-43 shows that 518 wind projects have been withdrawn from the serial queue. Of those 518 wind projects, 43 projects (8.3 percent) were offshore wind. Table 12-44 shows that those 518 wind projects that have been withdrawn from the serial queue totaled 92,692.9 MW. Of the 92,692.9 MW of withdrawn wind projects, 16,787.2 MW (18.1 percent) were offshore wind projects.

Solar Project Analysis

Table 12-45 shows the status of all solar generation projects by number of projects that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 320 solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, 98 projects (30.6 percent) are located in the AEP Zone.

Table 12-45 Status of all solar generation serial queue projects by zone (number of projects): December 31, 2025

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	11	27	0	25	4	3	2	7	3	3	79	20	3	56	5	0	1	9	3	6	46	0	313
	Upgrade	2	9	0	6	2	0	1	4	3	1	26	12	2	12	0	0	0	1	0	3	4	0	88
Under Construction	New Generation	2	19	0	4	5	0	1	1	0	0	14	4	1	2	0	0	0	5	0	2	1	0	61
	Upgrade	0	2	0	0	1	0	0	0	0	0	6	2	0	2	0	0	0	1	0	0	0	0	14
Suspended	New Generation	1	19	1	8	3	0	1	0	1	0	13	4	0	2	3	0	0	12	2	6	0	0	76
	Upgrade	0	5	0	0	0	0	1	0	0	0	2	7	0	0	1	0	0	2	0	0	0	0	18
Withdrawn	New Generation	192	161	0	133	39	14	55	31	16	1	291	147	20	198	42	2	12	93	25	72	92	0	1,636
	Upgrade	4	13	0	10	4	0	7	2	0	0	32	2	1	9	2	0	0	9	3	5	3	0	106
Active	New Generation	0	44	0	5	7	0	6	6	1	0	18	2	4	3	0	0	0	13	0	8	0	0	117
	Upgrade	0	9	0	1	0	0	3	2	0	0	9	0	1	0	0	0	0	1	0	8	0	0	34
Total Projects	New Generation	206	270	1	175	58	17	65	45	21	4	415	177	28	261	50	2	13	132	30	94	139	0	2,203
	Upgrade	6	38	0	17	7	0	12	8	3	1	75	23	4	23	3	0	0	14	3	16	7	0	260

Table 12-46 shows the status of all solar projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 25,586.5 MW of solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation serial queue, 11,710.1 MW (45.8 percent) are located in the AEP Zone.

Table 12-46 Status of all solar generation serial queue projects by zone (MW): December 31, 2025

		Project MW																					
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	67.6	3,233.9	0.0	752.1	548.0	31.1	59.0	699.2	214.9	45.9	4,491.7	478.5	165.0	431.3	160.0	0.0	3.3	326.4	35.6	140.0	241.9	0.0	12,125.3
	Upgrade	0.0	557.0	0.0	60.0	60.0	0.0	50.0	144.8	85.0	8.3	492.8	39.8	40.0	13.1	0.0	0.0	0.0	0.0	0.0	10.0	3.8	0.0	1,564.6
Under Construction	New Generation	11.6	2,907.6	0.0	241.8	337.0	0.0	116.0	300.0	0.0	0.0	2,184.0	318.9	70.0	30.8	0.0	0.0	0.0	255.5	0.0	160.0	6.0	0.0	6,939.2
	Upgrade	0.0	110.0	0.0	0.0	56.0	0.0	0.0	0.0	0.0	0.0	159.9	40.0	0.0	19.8	0.0	0.0	0.0	6.5	0.0	0.0	0.0	0.0	392.2
Suspended	New Generation	149.3	2,060.1	40.0	314.8	212.9	0.0	210.0	0.0	100.0	0.0	1,336.9	210.8	0.0	17.0	204.6	0.0	0.0	342.4	40.0	116.8	0.0	0.0	5,355.6
	Upgrade	0.0	129.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	53.0	131.5	0.0	0.0	20.0	0.0	0.0	30.0	0.0	0.0	0.0	0.0	413.5
Withdrawn	New Generation	2,300.4	12,548.9	0.0	3,775.6	2,259.2	112.3	4,217.1	2,215.5	689.4	20.0	18,997.0	2,515.4	1,266.9	1,631.3	1,249.7	198.0	124.2	3,054.3	283.9	1,875.1	590.2	0.0	59,924.3
	Upgrade	172.5	473.0	0.0	140.7	279.7	0.0	185.0	62.0	0.0	0.0	1,287.6	15.0	70.0	23.8	40.0	0.0	0.0	90.0	3.6	141.0	1.3	0.0	2,985.2
Active	New Generation	0.0	5,495.9	0.0	482.6	754.0	0.0	554.9	447.8	49.0	0.0	1,576.8	49.8	271.0	51.6	0.0	0.0	0.0	566.8	0.0	195.5	0.0	0.0	10,495.7
	Upgrade	0.0	1,007.5	0.0	78.4	0.0	0.0	190.0	58.5	0.0	0.0	418.0	0.0	40.0	0.0	0.0	0.0	0.0	42.0	0.0	155.9	0.0	0.0	1,990.3
Total Projects	New Generation	2,528.9	26,246.4	40.0	5,566.9	4,111.1	143.4	5,157.0	3,662.5	1,053.3	65.9	28,586.4	3,573.4	1,772.9	2,162.0	1,614.3	198.0	127.5	4,545.4	359.5	2,487.4	838.1	0.0	94,840.1
	Upgrade	172.5	2,276.5	0.0	279.1	395.7	0.0	475.0	265.3	85.0	8.3	2,411.3	226.3	150.0	56.7	60.0	0.0	0.0	168.5	3.6	306.9	5.1	0.0	7,345.8

Of the 320 solar units in the serial queue as of December 31, 2025, in the status of active, under construction or suspended, 16 units, representing 848.6 MW had a projected in service date prior to January 1, 2025 and 304 units, representing 24,737.9 MW had a projected in service date between January 1, 2025, and December 31, 2031.

Battery Project Analysis

Table 12-47 shows the status of all battery generation projects by number of projects that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 44 battery projects currently active, suspended or under construction in the PJM generation serial queue, 12 projects (27.3 percent) are located in the AEP Zone.

Table 12-47 Status of all battery generation serial queue projects by zone (number of projects): December 31, 2025

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0	3	0	2	0	2	7	1	4	0	1	0	0	7	0	0	1	0	0	1	2	0	31
	Upgrade	0	1	0	1	0	0	0	1	1	0	0	0	0	3	0	0	0	2	0	0	0	0	9
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	3	0	0	1	0	0	0	0	0	0	0	0	4
	Upgrade	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	4	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	1	0	2	0	0	8
	Upgrade	0	1	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Withdrawn	New Generation	12	29	0	5	6	27	21	1	3	2	29	25	2	40	6	0	4	6	2	10	9	0	239
	Upgrade	7	13	0	11	1	0	6	2	1	0	18	3	1	7	4	0	3	11	0	4	0	0	92
Active	New Generation	2	6	0	0	0	0	1	1	0	0	3	0	0	3	0	0	0	0	0	0	4	0	20
	Upgrade	0	1	0	1	0	0	3	1	0	0	1	0	0	0	1	0	0	0	0	0	0	0	8
Total Projects	New Generation	14	42	0	7	6	29	29	3	7	2	36	26	2	51	6	0	5	7	2	13	15	0	302
	Upgrade	7	16	0	13	1	0	10	4	3	0	20	3	1	10	5	0	3	13	0	4	0	0	113

Table 12-48 shows the status of all battery projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 3,106.1 MW of battery generation currently active, suspended or under construction in the PJM generation serial queue, 819.2 MW (26.4 percent) are located in the AEP Zone.

Table 12-48 Status of all battery generation serial queue projects by zone (MW): December 31, 2025

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	10.0	0.0	12.5	0.0	3.5	86.0	12.0	16.0	0.0	20.0	0.0	0.0	112.8	0.0	0.0	1.0	0.0	0.0	20.0	3.0	0.0	296.8
	Upgrade	0.0	4.0	0.0	27.4	0.0	0.0	0.0	8.0	4.0	0.0	0.0	0.0	0.0	8.0	0.0	0.0	0.0	28.4	0.0	0.0	0.0	0.0	79.8
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	335.7	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	355.7
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0
Suspended	New Generation	0.0	197.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.0	0.0	0.0	0.0	0.0	0.0	160.0	0.0	170.0	0.0	0.0	536.0
	Upgrade	0.0	40.0	0.0	0.0	0.0	0.0	10.0	0.0	52.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	102.2
Withdrawn	New Generation	303.0	1,047.4	0.0	237.0	106.1	580.6	387.0	19.9	75.5	75.0	1,190.4	600.5	46.3	976.1	395.9	0.0	4.3	470.8	21.0	424.8	421.5	0.0	7,383.0
	Upgrade	20.0	769.2	0.0	219.0	20.3	0.0	125.3	95.0	20.0	0.0	441.0	54.0	28.0	55.1	174.0	0.0	60.0	76.0	0.0	40.0	0.0	0.0	2,196.9
Active	New Generation	50.0	530.0	0.0	0.0	0.0	0.0	20.0	85.0	0.0	0.0	240.0	0.0	0.0	290.0	0.0	0.0	0.0	0.0	0.0	0.0	525.0	0.0	1,740.0
	Upgrade	0.0	52.2	0.0	20.0	0.0	0.0	150.0	40.0	0.0	0.0	40.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	322.2
Total Projects	New Generation	353.0	1,784.4	0.0	249.5	106.1	584.1	493.0	116.9	91.5	75.0	1,786.1	609.5	46.3	1,398.9	395.9	0.0	5.3	630.8	21.0	614.8	949.5	0.0	10,311.5
	Upgrade	20.0	865.4	0.0	266.4	20.3	0.0	285.3	143.0	76.2	0.0	531.0	54.0	28.0	63.1	194.0	0.0	60.0	104.4	0.0	40.0	0.0	0.0	2,751.1

Of the 44 battery units in the serial queue as of December 31, 2025, in the status of active, under construction or suspended, two units, representing 40.0 MW had a projected in service date prior to January 1, 2025 and 42 units, representing 3,066.1 MW had a projected in service date between January 1, 2025, and December 31, 2030.

Renewable Hybrid Project Analysis

Table 12-49 shows the status of all renewable hybrid generation projects (solar + storage, solar + wind and wind + storage) by number of projects that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone.[74] Of the 26 renewable hybrid projects currently active, suspended or under construction in the PJM generation serial queue, seven projects (26.9 percent) are located in the DOM Zone.

Table 12-49 Status of all renewable hybrid generation serial queue projects by zone (number of projects): December 31, 2025

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0	0	0	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	5	0	7
	Upgrade	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
Under Construction	New Generation	0	0	0	0	3	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	4
	Upgrade	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	6	16	0	13	7	0	7	0	0	2	35	1	9	4	11	0	0	12	1	20	9	0	153
	Upgrade	0	1	0	2	0	0	0	0	0	0	1	0	0	0	1	0	0	0	0	1	0	0	6
Active	New Generation	1	4	0	2	0	0	1	0	0	0	6	2	0	1	0	0	0	0	0	2	0	0	19
	Upgrade	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1
Total Projects	New Generation	7	21	0	16	10	0	8	0	0	2	42	4	9	5	11	0	0	12	1	22	14	0	184
	Upgrade	0	3	0	2	0	0	1	0	0	0	2	0	0	0	1	0	0	0	0	1	0	0	10

Table 12-50 shows the status of all renewable hybrid projects by MW that entered PJM generation serial queues from January 1, 1997, through July 10, 2023, by zone. Of the 2,079.2 MW of renewable hybrid generation currently active, suspended or under construction in the PJM generation serial queue, 809.0 MW (38.9 percent) are located in the AEP Zone.

Table 12-50 Status of all renewable hybrid generation serial queue projects by zone (MW): December 31, 2025

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	0.0	0.0	186.0	0.0	0.0	0.0	0.0	0.0	0.0	17.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.1	0.0	208.1
	Upgrade	0.0	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2
Under Construction	New Generation	0.0	0.0	0.0	0.0	57.7	0.0	0.0	0.0	0.0	0.0	0.0	3.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	61.6
	Upgrade	0.0	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0
Suspended	New Generation	0.0	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	150.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	114.5	4,553.8	0.0	460.5	659.9	0.0	1,004.9	0.0	0.0	37.5	2,759.2	10.0	1,252.0	110.0	97.1	0.0	0.0	475.0	20.0	195.0	49.9	0.0	11,799.2
	Upgrade	0.0	400.0	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7	0.0	0.0	0.0	0.0	40.0	0.0	0.0	460.0
Active	New Generation	38.0	559.0	0.0	380.0	0.0	0.0	19.9	0.0	0.0	0.0	534.0	12.7	0.0	70.0	0.0	0.0	0.0	0.0	0.0	60.0	0.0	0.0	1,673.6
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	94.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	94.0
Total Projects	New Generation	152.5	5,262.8	0.0	1,026.5	717.6	0.0	1,024.8	0.0	0.0	37.5	3,310.2	26.5	1,252.0	180.0	97.1	0.0	0.0	475.0	20.0	255.0	54.9	0.0	13,892.4
	Upgrade	0.0	503.2	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	94.0	0.0	0.0	0.0	3.7	0.0	0.0	0.0	0.0	40.0	0.0	0.0	657.2

74 PJM does not currently have a definition of a hybrid resource.

Of the 26 renewable hybrid units in the serial queue as of December 31, 2025, in the status of active, under construction or suspended, two units, representing 6.6 MW had a projected in service date prior to January 1, 2025 and 24 units, representing 2,072.6 MW had a projected in service date between January 1, 2025, and December 31, 2031.

New Service Requests Cycle Process[75]

Interconnection Process Studies and Agreements

The transition to the new queue process began on July 10, 2023. The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[76] Each cycle consists of the: application phase, phase I, decision point I, phase II, decision point II, phase III, decision point III, and the final agreement negotiation phase.

Application Phase

The application phase includes the submission and review of a new service request. A new service request could be a request to interconnect a new generating facility, a request to increase the capability of an existing generating facility, a request to interconnect a merchant transmission facility, a request to increase the capability of an existing merchant transmission facility, a request to interconnect a generating facility to distribution facilities located in PJM that are to be used for transmission of power in interstate commerce, and to make wholesale sales or a long term firm transmission service request outside of the 18 month available transfer capability (ATC) horizon. The deadline for submitting applications for a new cycle corresponds with the completion of phase II of the previous cycle. For an application to be considered complete, and included in a cycle, PJM must receive a completed and executed application and studies agreement (ASA), required technical information, a wire transfer for the entirety of study deposit, a wire transfer or letter of credit for the entirety of Readiness Deposit No. 1 and, for generation requests, evidence of site control.

Phase I

Phase I of a cycle begins after the application phase of a cycle is completed and a group of valid new service requests is established. During phase I of a cycle, PJM performs a phase I system impact study (SIS). The phase I SIS is conducted on an aggregate basis within a cycle, and results are provided in a single cycle format. The phase I SIS results are posted on PJM's website. The phase I SIS evaluates each new service request on a summer peak, winter peak and light load RTEP base case. PJM only performs a load flow analysis during the phase I system impact study. In phase I of the cycle, PJM also conducts an affected system screen and provides each affected system operator with a list of new service requests within the cycle including potential impacts to their system. During phase I, PJM creates both the short circuit and stability base cases that will be used in the phase II SIS.

Decision Point I

New service requests that are studied in phase I will enter decision point I. After reviewing the results of the phase I SIS, the project developer must decide whether or not to move forward to phase II of the process. Decision point I starts on the first business day following the end of phase I and closes 30 calendar days later. Before the close of decision point I, the project developer can choose to either remain in the cycle by meeting the decision point I requirements or to withdraw its new service request. If a project developer fails to submit all required deposits, evidence, and data before the close of decision point I, the new service request will be terminated and withdrawn.

Phase II

After the decision point I phase of a cycle is completed and a group of valid new service requests is established, phase II of a cycle will begin. During phase II of a cycle, PJM performs the phase II SIS. PJM retools the load flow results from the phase I SIS (summer peak, winter peak and light load) based on decisions made during decision point I. PJM also conducts any required voltage analyses, performs short circuit and stability analyses and coordinates with affected systems to confirm which projects in the cycle will require affected system studies. If the affected system operator indicates that an affected system study is required, PJM notifies the project developer of the need for an affected system study and the requirement to execute an affected system study agreement with the impacted affected system operator. If applicable and available, PJM includes the results of

75 Material in this section is based on information found in PJM Manual 14H. See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 03 (September 25, 2025).

76 See "Interconnection Process Reform," presented at April 27, 2022 meeting of the Members Committee. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.

the affected system operator's affected system study in the phase II SIS results.

The phase II SIS includes a facilities study by the affected transmission owner that identifies any required network upgrades. The facilities studies will include good faith estimates of the costs to be charged to each affected new service customer for the network upgrades that are necessary to accommodate each new service request evaluated in the study, the time required to complete detailed design and construction of the facilities and upgrades and a description of any site-specific environmental issues or requirements that could reasonably be anticipated to affect the cost or time required to complete construction of such facilities and upgrades.

Decision Point II

New service requests that are studied in phase II will enter decision point II. After reviewing the results of the phase II SIS, the project developer must decide whether or not to move forward to phase III of the process. Decision point II starts on the first business day following the end of phase II and closes 30 calendar days later. Before the close of decision point II, the project developer can choose to either remain in the cycle by meeting the decision point II requirements or to withdraw its new service request. If a project developer fails to submit all required deposits, evidence, and data before the close of decision point II, the new service request will be terminated and withdrawn.

Phase III

After the decision point II phase of a cycle is completed and a group of valid new service requests is established, phase III of a cycle will begin. During phase III of a cycle, PJM performs the phase III SIS. PJM retools the load flow, short circuit and stability results from the phase II SIS based on decisions made during decision point II. PJM also coordinates with affected systems to conduct any studies required to determine the final impact of a new service request on any affected system. If applicable and available, PJM includes the results of the affected system operator's final affected system study in the phase III SIS results.

Decision Point III

New service requests that are studied in phase III will enter decision point III. After reviewing the results of the phase III SIS, the project developer must decide whether or not to move forward to the final agreement negotiation phase. Decision point III starts on the first business day following the end of phase III and runs concurrently with the final agreement negotiation phase. The project developer can choose to either remain in the cycle by meeting the decision point III requirements or to withdraw its new service request. If a project developer fails to submit all required deposits, evidence, and data before the close of decision point III, the new service request will be terminated and withdrawn.

Final Agreement Negotiation Phase

The final agreement negotiation phase starts on the first business day immediately following the end of phase III, and runs concurrently with decision point III. The purpose of the final agreement negotiation phase is to negotiate, execute and enter into the applicable final interconnection related service agreement, conduct any remaining analyses or updated analyses based on new service requests withdrawn during decision point III and adjust the security obligation based on new service requests withdrawn during decision point III and/or during the final agreement negotiation phase. PJM uses reasonable efforts to complete the final agreement negotiation phase within 60 days. Table 12-51 is an overview of the agreements used in the new service requests cycle process.

Table 12-51 Final agreements: new service requests cycle process

Agreement	Purpose
Generation Interconnection Agreement (GIA)	The GIA defines the obligations of the project developer regarding cost responsibility for any required system upgrades. The GIA also confers the rights associated with the interconnection of a generating facility as a capacity resource and any operational restrictions or other limitations on which those rights depend. For transmission project developers, the GIA confers transmission injection and withdrawal rights and applicable incremental delivery rights and incremental auction revenue rights.The GIA further identifies any changes in construction responsibility from the standard option for transmission owner interconnection facilities due to the project developer exercising the negotiated contract option or option to build.
Construction Service Agreement (CSA)	The CSA defines the standard terms and conditions of the interconnection, including construction responsibility, includes a construction schedule and contains notification and insurance obligations.The CSA is included as a schedule within a GIA; however, a stand-alone CSA may be implemented in circumstances in which network upgrades to the system of a transmission owner are required to accommodate the interconnection request of a project developer, whose facilities do not directly interconnect to the transmission owner's system. Examples include project developers who are affected system customers (external to the PJM region), that require network upgrades to be constructed by PJM transmission owners, or project developers requiring upgrades to be constructed by PJM transmission owners, other than their interconnecting transmission owner
Upgrade Construction Service Agreement (USCA)	A new service customer who proposes to make an upgrade to an existing transmission facility or who seeks incremental auction revenue rights (IARRs) will receive an upgrade construction service agreement after their study process is completed.
Network Upgrade Cost Responsibility Agreement (NUCRA)	The NUCRA refers to the agreement entered into by two or more project developers and PJM, relating to construction of common use upgrades (network upgrades needed for the interconnection of generating or merchant transmission facilities for more than one project developer that share cost responsibility) and coordination of the construction and interconnection of associated generating facilities. A separate NUCRA will be executed for each set of common use upgrades on the system of a specific transmission owner that is associated with the interconnection of a generating facility or merchant transmission facility. The NUCRA includes the identified common use upgrades scope and schedule of work, the cost responsibility for the project developers that share cost responsibility, as well as the terms and conditions for the agreement.
Wholesale Market Participation Agreement (WMPA)	Developers interconnecting to non-FERC jurisdictional facilities who intend to participate in the PJM wholesale market will receive a three party agreement (WMPA). The WMPA is a non-Tariff agreement which must be filed with the FERC. The WMPA is essentially an ISA without interconnection provisions.

Transition Cycle 1 (TC1)

On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions to improve the queue process.[77] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[78] This change will allow projects to move forward based on a first ready/first out analysis, where readiness is demonstrated through site control and financial milestones and there is an option to exit the study process early based on system impacts. The transition to the new queue process began on July 10, 2023.

On May 20, 2024, PJM completed the phase I system impact study for transition cycle 1 (TC1). Developers had 30 days (until June 20, 2024) to decide whether to proceed with their new service requests into the next study phase of TC1 or to withdraw their projects. Continuing with phase II required developers to meet the decision point I requirements (including additional readiness deposits and proof of site control).[79]

On December 20, 2024, PJM completed the phase II system impact study for TC1. Developers had 30 days (until January 19, 2025) to decide whether to proceed with their new service requests into the next study phase of TC1 or to withdraw their projects. Continuing with phase III requires developers to meet the decision point II requirements, (including additional readiness deposits and proof of site control).[80]

On April 21, 2025, phase III of TC1 began. During phase III, PJM performed the phase III SIS. PJM retooled the load flow, short circuit and stability results from the phase II SIS based on decisions made during decision point II. PJM also coordinated with affected systems to conduct any studies required to determine the final impact of a new service request on any affected system. Phase III of TC1 completed on September 19, 2025. The TC1 decision point III ran for 30 days, and completed on October 21, 2025. Additionally, the TC1 final agreement phase also began at the completion of phase III, and completed on November 20, 2025.

77 181 FERC ¶ 61,162 (2022).
78 See "Interconnection Process Reform," presented at April 27, 2022 meeting of the Members Committee. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.
79 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 03 (September 25, 2025) for a complete list of all readiness requirements.
80 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 03 (September 25, 2025) for a complete list of all readiness requirements.

Planned Generation Additions

TC1 is comprised of 312 proposed generation projects. Those projects make up 40,650.1 MW. On December 31, 2025, all projects in TC1 were either in the status of active or were withdrawn from the cycle. Table 12-52 shows each status by unit type. Of the 40,650.1 MW in TC1, 14,897.2 MW (36.6 percent) were active and 25,752.9 MW (63.4 percent) were withdrawn. Of the 14,897.2 MW in the status of active, 7,730.2 MW (51.9 percent) were solar projects, 3,989.9 MW (26.8 percent) were wind projects, and 1,757.2 MW (11.8 percent) were battery projects.

Table 12-52 Transition cycle 1 project status (MW) by unit type: December 31, 2025

	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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	1,757.2	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,730.2	851.0	0.0	0.0	0.0	0.0	0.0	3,989.9	0.0	14,897.2
Withdrawn	4,525.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13,199.8	3,257.2	199.0	0.0	0.0	0.0	0.0	4,571.7	0.0	25,752.9
Total	6,282.4	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20,930.0	4,108.2	199.0	0.0	0.0	0.0	0.0	8,561.6	0.0	40,650.1

Table 12-53 shows the projects in TC1 with a status of active or under construction, by unit type, and control zone. As of December 31, 2025, 14,897.2 MW were in TC1 for construction through 2031. Table 12-53 also shows the planned retirements for each zone.

Table 12-53 Transition cycle 1 totals for projects (active and under construction) by LDA, control zone and unit type (MW): December 31, 2025

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total Queue Capacity	Planned Retirements
EMAAC	ACEC	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0	175.1
	DPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.4
	JCPLC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	65.0
	PECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	760.0
	PSEG	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	REC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EMAAC Total	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0	1,016.5
SWMAAC	BGE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,975.0
	PEPCO	500.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	500.0	0.0
	SWMAAC Total	500.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	500.0	1,975.0
WMAAC	MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	PE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	187.0	245.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	432.0	0.0
	PPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	WMAAC Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	187.0	245.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	432.0	0.0
Non-MAAC	AEP	607.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,115.0	500.0	0.0	0.0	0.0	0.0	0.0	755.0	0.0	2,977.2	2,620.0
	AMPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	APS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	ATSI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.0	0.0
	COMED	330.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,853.1	0.0	0.0	0.0	0.0	0.0	0.0	745.9	0.0	4,929.0	2,607.9
	DAY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	206.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	206.6	0.0
	DUKE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DLCO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DOM	250.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,532.0	0.0	0.0	0.0	0.0	0.0	0.0	2,489.0	0.0	4,840.0	0.0
	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	824.5	106.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	930.5	116.0
	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	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	0.0	0.0	0.0
	Non-MAAC Total	1,187.2	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,543.2	606.0	0.0	0.0	0.0	0.0	0.0	3,989.9	0.0	13,895.2	5,343.9
Total		1,757.2	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,730.2	851.0	0.0	0.0	0.0	0.0	0.0	3,989.9	0.0	14,897.2	8,335.4

Table 12-54 shows that on December 31, 2025 there were 14,897.2 MW, on an energy basis, of which 7,285.6 MW are on a capacity basis that requested CIRs, in TC1 in the status of active or under construction. Table 12-54 also shows the total capacity MW adjusted for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 7,285.6 MW, on a capacity basis that requested CIRs in TC1 in the status of active or under construction, 1,901.4 MW (26.1 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 569 MW, on a capacity basis that requested CIRs, of thermal projects (including CT natural gas projects) requested in TC1 in the status of active, 347.1 MW (61.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 3,837.9 MW, on a capacity basis that requested CIRs, of solar projects requested in TC1 in the status of active or under construction, 307.0 MW (8.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 1,353.3 MW, on a capacity basis that requested CIRs, of battery projects requested in TC1 in the status of active or under construction, 784.9 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 5,363.3 MW, on a capacity basis that requested CIRs, of renewable projects requested in TC1 in the status of active or under construction, 769.3 MW (14.3 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Table 12-54 Transition cycle 1 totals for projects (active and under construction) by unit type adjusted for ELCC derates (MW): December 31, 2025

	Energy (MW)	Capacity (MW)	
Unit Type	Total	Total	ELCC Adjusted
Battery	1,757.2	1,353.3	784.9
CC	0.0	0.0	0.0
CT - Natural Gas	569.0	569.0	347.1
CT - Oil	0.0	0.0	0.0
CT - Other	0.0	0.0	0.0
Fuel Cell	0.0	0.0	0.0
Hydro - Pumped Storage	0.0	0.0	0.0
Hydro - Run of River	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0
RICE - Natural Gas	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	7,730.2	3,837.9	307.0
Solar + Storage	851.0	494.3	39.5
Solar + Wind	0.0	0.0	0.0
Steam - Coal	0.0	0.0	0.0
Steam - Natural Gas	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0
Wind	3,989.9	1,031.1	422.8
Wind + Storage	0.0	0.0	0.0
Total	14,897.2	7,285.6	1,901.4

Withdrawn Projects

Table 12-55 shows the status of all TC1 projects as they have progressed through the cycle process. Of the 312 projects included in TC1, 121 projects (38.8 percent of all projects and 38.9 percent of the total MW) were withdrawn during phase I or decision point I, 62 projects (19.9 percent of all projects and 17.3 percent of the total MW) were withdrawn during phase II or decision point II and 40 projects (12.8 percent of all projects and 7.1 percent of the total MW) were withdrawn during phase III or decision point III. On December 31, 2025, 89 projects (28.6 percent of all projects and 36.6 percent of the total MW) remain active or have reached the final agreement stage in TC1.

Table 12-55 Transition cycle 1 status: December 31, 2025

	Number of Projects	Percent of Projects	MW Energy	Percent of MW Energy
Transition cycle 1 approved projects	312	100.0%	40,650.1	100.0%
Withdrawn prior to start of phase I	0	0.0%	0.0	0.0%
Withdrawn during phase I or decision point I	121	38.8%	15,821.8	38.9%
Withdrawn during phase II or decision point II	62	19.9%	7,044.5	17.3%
Withdrawn during phase III or decision point III	40	12.8%	2,886.5	7.1%
Active as of December 31, 2025	76	24.4%	10,255.2	25.2%
In final agreement stage as of December 31, 2025	13	4.2%	4,642.0	11.4%
Under construction	0	0.0%	0.0	0.0%
In Service	0	0.0%	0.0	0.0%

Table 12-56 shows 40,650.1 MW have entered TC1. Table 12-56 presents totals by fuel type and projected in service date as of December 31, 2025. Of the 40,650.1 MW to enter TC1, 569.0 MW (1.4 percent) were thermal units.

Table 12-56 Transition cycle 1 total (MW Energy) by unit type and projected in service year: December 31, 2025

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	90.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	90.0
2019	779.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,673.3	1,826.8	0.0	0.0	0.0	0.0	0.0	2,112.2	0.0	7,391.7
2020	3,745.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10,496.6	1,430.4	199.0	0.0	0.0	0.0	0.0	2,459.6	0.0	18,331.2
2021	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	687.6	0.0	0.0	0.0	0.0	0.0	0.0	405.0	0.0	1,192.6
2022	432.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,768.5	450.0	0.0	0.0	0.0	0.0	0.0	595.9	0.0	3,246.6
2023	255.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,047.1	401.0	0.0	0.0	0.0	0.0	0.0	500.0	0.0	4,203.1
2024	300.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,253.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,553.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0
2029	0.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	569.0
2030	500.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	500.0
2031	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	414.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	564.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	500.0	0.0	0.0	0.0	0.0	0.0	0.0	2,489.0	0.0	2,989.0
Total	6,282.4	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20,930.0	4,108.2	199.0	0.0	0.0	0.0	0.0	8,561.6	0.0	40,650.1

Table 12-57 shows there were 14,897.2 MW in TC1 in the status of active or under construction as of December 31, 2025. Table 12-57 presents totals by fuel type and projected in service date. Of the 14,897.2 MW, 569.0 MW (3.8 percent) are thermal units.

Table 12-57 Transition cycle 1 total (MW Energy) by unit type and projected in service year (active and under construction): December 31, 2025

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	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	0.0	0.0	0.0	60.0
2021	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	687.6	0.0	0.0	0.0	0.0	0.0	0.0	405.0	0.0	1,192.6
2022	432.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,768.5	450.0	0.0	0.0	0.0	0.0	0.0	595.9	0.0	3,246.6
2023	255.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,047.1	401.0	0.0	0.0	0.0	0.0	0.0	500.0	0.0	4,203.1
2024	300.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,253.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,553.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0
2029	0.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	569.0
2030	500.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	500.0
2031	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	414.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	564.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	500.0	0.0	0.0	0.0	0.0	0.0	0.0	2,489.0	0.0	2,989.0
Total	1,757.2	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,730.2	851.0	0.0	0.0	0.0	0.0	0.0	3,989.9	0.0	14,897.2

Table 12-58 shows there were 25,752.9 MW withdrawn from TC1. Table 12-58 presents totals by fuel type and projected in service date. Of the 25,752.9 MW withdrawn from TC1, none were identified as thermal units.

Table 12-58 Transition cycle 1 total (MW Energy) by unit type and projected in service year (withdrawn): December 31, 2025

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	90.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	90.0
2019	779.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,673.3	1,826.8	0.0	0.0	0.0	0.0	0.0	2,112.2	0.0	7,391.7
2020	3,745.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10,436.6	1,430.4	199.0	0.0	0.0	0.0	0.0	2,459.6	0.0	18,271.2
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	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	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	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,525.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13,199.8	3,257.2	199.0	0.0	0.0	0.0	0.0	4,571.7	0.0	25,752.9

Analysis by Fuel Group

Table 12-59 shows the number of projects that entered TC1 by year and by fuel group. The fuel groups are nuclear units, renewable units (including hydro run of river, solar and wind units (including renewable solar and wind hybrids), storage units (including battery and pumped storage hydro units), thermal units (including combined cycle, CT natural gas and oil, RICE natural gas and oil and steam coal, natural gas and oil) and other units (all other fuels). The 312 projects submitted to TC1 were made up of 233 renewable projects (74.7 percent), 77 storage projects (24.7 percent) and two thermal projects (0.6 percent).

Table 12-59 Transition cycle 1 number of projects by fuel group: December 31, 2025

	Fuel Group										
Year Entered	Nuclear	Percent Nuclear	Renewable	Percent Renewable	Storage	Percent Storage	Thermal	Percent Thermal	Other	Percent Other	Total
2018	0	0.0%	4	80.0%	0	0.0%	1	20.0%	0	0.00%	5
2019	0	0.0%	57	78.1%	15	20.5%	1	1.4%	0	0.00%	73
2020	0	0.0%	172	73.5%	62	26.5%	0	0.0%	0	0.00%	234
Total	0	0.0%	233	74.7%	77	24.7%	2	0.6%	0	0.00%	312

As of December 31, 2025, there were 89 projects in TC1 in the status of active or under construction. Those 89 projects consisted of 70 renewable projects (78.7 percent of all projects and 84.4 percent of the nameplate MW), 18 storage projects (20.2 percent of all projects and 11.8 percent of the nameplate MW) and one thermal project (1.1 percent of all projects and 3.8 percent of the nameplate MW) (Table 12-60).

Table 12-60 Transition cycle 1 details by fuel group: December 31, 2025

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	0	0.0%	0.0	0.0%
Renewable	70	78.7%	12,571.0	84.4%
Storage	18	20.2%	1,757.2	11.8%
Thermal	1	1.1%	569.0	3.8%
Other	0	0.0%	0.0	0.0%
Total	89	100.0%	14,897.2	100.0%

Analysis by Unit Type and Project Classification

Table 12-61 shows the status of all new generation projects in TC1 by unit type and project classification as of December 31, 2025. Project classification is defined as either new generation or an uprate in which existing resources are modified to increase the economic maximum generation capability. There were 312 projects, representing 40,650.1 MW, entered into TC1. Of those, 312 projects, 223 projects, representing 25,752.9 MW (63.4 percent of the MW) withdrew prior to completion.

A total of 222 projects have been classified as new generation and 90 projects have been classified as upgrades. Natural gas, wind, solar and renewable hybrid projects (including solar + storage, solar + wind and wind + storage) have accounted for 235 projects (75.3 percent) of all 312 generation projects to enter TC1.

Table 12-61 Transition Cycle 1 status of all generation projects: December 31, 2025

		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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	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	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Under Construction	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	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	24	0	0	0	0	0	0	0	0	0	0	0	94	27	1	0	0	0	0	13	0	159
	Upgrade	35	0	1	0	0	0	0	0	0	0	0	0	21	4	0	0	0	0	0	3	0	64
Active	New Generation	8	0	1	0	0	0	0	0	0	0	0	0	39	5	0	0	0	0	0	10	0	63
	Upgrade	10	0	0	0	0	0	0	0	0	0	0	0	15	0	0	0	0	0	0	1	0	26
Total Projects	New Generation	32	0	1	0	0	0	0	0	0	0	0	0	133	32	1	0	0	0	0	23	0	222
	Upgrade	45	0	1	0	0	0	0	0	0	0	0	0	36	4	0	0	0	0	0	4	0	90

Table 12-62 shows the totals in Table 12-61 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, 22.2 percent of all battery projects in TC1 classified as upgrades were active and 77.8 percent of battery projects classified as upgrades were withdrawn from TC1 as of December 31, 2025.

Table 12-62 Transition Cycle 1 status of all generation projects as a percent of total projects by classification: December 31, 2025

		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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	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%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Under Construction	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%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Withdrawn	New Generation	75.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	70.7%	84.4%	100.0%	0.0%	0.0%	0.0%	0.0%	56.5%	0.0%	71.6%
	Upgrade	77.8%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	58.3%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	75.0%	0.0%	71.1%
Active	New Generation	25.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	29.3%	15.6%	0.0%	0.0%	0.0%	0.0%	0.0%	43.5%	0.0%	28.4%
	Upgrade	22.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	41.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	25.0%	0.0%	28.9%

Table 12-63 shows the total MW of projects in TC1 by unit type and project classification. For example, the 24 new generation battery projects that have been withdrawn from TC1 as of December 31, 2025, (as shown in Table 12-61) constitute 3,329.7 MW. The 94 new generation solar projects that have been withdrawn in the same time period constitute 11,159.8 MW.

Table 12-63 Transition cycle 1 status of all generation (MW) projects: December 31, 2025

		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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Under Construction	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	3,329.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11,159.8	2,994.8	199.0	0.0	0.0	0.0	0.0	4,105.2	0.0	21,788.4
	Upgrade	1,195.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,040.0	262.4	0.0	0.0	0.0	0.0	0.0	466.6	0.0	3,964.5
Active	New Generation	1,295.0	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,420.1	851.0	0.0	0.0	0.0	0.0	0.0	3,839.9	0.0	12,974.9
	Upgrade	462.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,310.1	0.0	0.0	0.0	0.0	0.0	0.0	150.0	0.0	1,922.3
Total Projects	New Generation	4,624.7	0.0	569.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17,579.9	3,845.8	199.0	0.0	0.0	0.0	0.0	7,945.1	0.0	34,763.4
	Upgrade	1,657.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,350.1	262.4	0.0	0.0	0.0	0.0	0.0	616.6	0.0	5,886.8

Table 12-64 shows the MW totals in Table 12-63 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, 27.9 percent of all battery project MW in TC1 classified as upgrades were active and 72.1 percent of battery project MW classified as upgrades were withdrawn from TC1 as of December 31, 2025.

Table 12-64 Transition cycle 1 status of all generation projects as percent of total MW in project classification: December 31, 2025

		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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	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%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Under Construction	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%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Withdrawn	New Generation	72.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	63.5%	77.9%	100.0%	0.0%	0.0%	0.0%	0.0%	51.7%	0.0%	62.7%
	Upgrade	72.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	60.9%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	75.7%	0.0%	67.3%
Active	New Generation	28.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	36.5%	22.1%	0.0%	0.0%	0.0%	0.0%	0.0%	48.3%	0.0%	37.3%
	Upgrade	27.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	39.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	24.3%	0.0%	32.7%

Transition Cycle 2 (TC2) and Reliability Resource Initiative (RRI)

On December 13, 2024, PJM submitted modifications to its Open Access Transmission Tariff to add provisions, through a one-time reliability based expansion of the projects in TC2.[81] The MMU supports the stated goals of the December 13th Filing, and supported approval of the December 13th Filing, but also identified significant flaws that compromise the ability of the proposal to achieve its stated goals.[82] PJM's RRI scoring criteria placed undue emphasis on ELCC values rather than on dispatchability. PJM stated that the goal is to be fuel and technology neutral. That is not the appropriate objective when there are defined differences in reliability and dispatchability across resource types, by fuel and technology. The goal of the December 13th Filing should have been to select the most reliable fuel and technology combinations. PJM also focused on an arbitrary number of projects (50) that could qualify as RRI projects rather than on a target level of MW needed for reliability. PJM should have identified the number of MW, with the required reliability characteristics, that it believes are needed to address PJM's identified reliability shortfall and use the RRI process to obtain those MW. PJM's RRI scoring criteria should have been a series of thresholds that must be met in sequence rather than a single formula that considers all elements simultaneously and assumes that the criteria are comparable through relative weights. The first threshold should have been that the resource is in the right location to address the identified locational reliability issue. The second threshold should have been that the operational characteristics of the resource fully address the identified reliability issue including technology and fuel source(s). The third threshold should have been commercial viability within a defined time period with detailed tracking and strong financial incentives. No RRI resource should have been approved unless it met all three thresholds.

In addition to the one time RRI process, the MMU recommends that PJM establish an ongoing expedited PJM managed queue process to identify commercially viable projects that could help eliminate or reduce the need for specific RMRs or that could address specific reliability needs and allow the identified projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.[83] While it is important to respect the existing, improved PJM queue process, it is also essential to provide strong and clear incentives for projects to actually resolve reliability issues and to actually guarantee timely in service dates in order to help ensure that the queue is not a mirage as it has been in significant part for its recent history. Recognizing that improved queue rules are being implemented, the history of queue projects becoming actual in service capacity resources suggests strongly that such incentives have not been provided by the queue process.

On February 11, 2025, the Commission approved the RRI tariff modifications.[84] The proposed RRI Tariff revisions created a second TC2 application window that enabled RRI projects to join TC2 and be studied for interconnection during the transition period.

PJM included a range of important enforceable provisions that help ensure that the selected RRI resources will actually go online as promised. These provisions include a must offer obligation which is essential to the efficacy of the entire filing as capacity resources that do not offer do not help solve the identified problem. The MMU supports these provisions.

PJM received 97 applications (28.6 GW) of RRI projects during the RRI application window. Of these projects, 48 involve uprates, in which existing resources are modified to increase the economic maximum generation capability, and 49 propose building new generation. The RRI application window did not limit the number and type of projects (or any restriction on fuel type of projects) that may apply to enter the RRI process. However, PJM restricted the number of RRI projects to be added to TC2 by scoring all the RRI applications using weighted criteria to determine the 50 projects that best satisfy the need for reliable capacity that can be available relatively quickly. The submitted RRI projects were reviewed to determine which projects will be added to TC2.

PJM reviewed the submitted RRI projects using the Commission approved scoring criteria, and approved 51

81 See *PJM Interconnection L.L.C.* Docket No. ER25-712 (December 13, 2024).

82 See IMM Comments. *PJM Interconnection L.L.C.* Docket No. ER25-712

83 The MMU has consistently supported a stronger role for PJM in addressing immediate reliability needs. As part of the CIR Transfer Efficiency initiative, the MMU proposed to allow PJM to initiate an expedited fast track process to address PJM identified reliability issues. The proposed expedited process would have allowed PJM to open a limited scope expedited reliability process to select projects that address the reliability issues. See "CIR Transfer Efficiency IMM Package," MMU presentation to the PJM Planning Committee (October 8, 2024), <https://www.monitoringanalytics.com/reports/Presentations/2024/IMM_PC_CIR_Transfer_Efficiency_IMM_Package_20241008_v2.pdf>.

84 190 FERC ¶ 61,084 (February 11, 2025).

projects (11,577.4 MW).[85] Table 12-65 shows the status of the 51 approved RRI projects by unit type. On December 31, 2025, all approved RRI projects were either in the status of active or were withdrawn from the cycle. Of the 11,577.4 MW of approved RRI projects, 7,951.4 MW (68.7 percent) were active and 3,626.0 MW (31.3 percent) were withdrawn. Of the 7,951.4 MW in the status of active, 4,862.6 MW (61.2 percent) were combined cycle projects, and 1,575.0 MW (19.8 percent) were battery projects.

Table 12-65 RRI project status (MW) by unit type: December 31, 2025

	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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	1,575.0	4,862.6	11.0	0.0	0.0	0.0	0.0	0.0	1,502.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,951.4
Withdrawn	700.0	2,926.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,626.0
Total	2,275.0	7,788.6	11.0	0.0	0.0	0.0	0.0	0.0	1,502.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11,577.4

Of the 51 approved RRI projects, nine (17.6 percent) have been withdrawn as of December 31, 2025. These nine projects were withdrawn at the request of the developer. Withdrawn RRI projects highlight the flaws in the project selection stage. A better approach would have been to select enough projects, using supported commercial operation date as a gating criterion, to meet a desired MW quantity (accounting for expected withdrawals) to ensure a reliable outcome rather than a set number of projects.

Table 12-66 shows that on December 31, 2025 there were 7,951.4 MW, on an energy basis, of which 7,498.8 MW are on a capacity basis that requested CIRs, of RRI projects in the status of active or under construction. Table 12-66 also shows the total capacity MW adjusted for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 7,498.8 MW, on a capacity basis that requested CIRs, of RRI projects in the status of active or under construction, 5,566.4 MW (74.2 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 4,579.9 MW, on a capacity basis that requested CIRs, of RRI combined cycle projects in the status of active or under construction, 3,389.1 MW (74.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 1,575.0 MW, on a capacity basis that requested CIRs, of RRI battery projects in the status of active or under construction, 913.5 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

85 The RRI proposal was to select the top 50 projects using the approved scoring criteria. The implemented scoring criteria resulted in a tie for the 50th project. This resulted in PJM selecting 51 projects as part of the RRI process.

Table 12-66 RRI totals for projects (active and under construction) by unit type adjusted for ELCC derates (MW): December 31, 2025

	Energy (MW)	Capacity (MW)	
Unit Type	Total	Total	ELCC Adjusted
Battery	1,575.0	1,575.0	913.5
CC	4,862.6	4,579.9	3,389.1
CT - Natural Gas	11.0	38.0	23.2
CT - Oil	0.0	0.0	0.0
CT - Other	0.0	0.0	0.0
Fuel Cell	0.0	0.0	0.0
Hydro - Pumped Storage	0.0	0.0	0.0
Hydro - Run of River	0.0	0.0	0.0
Nuclear	1,502.8	1,305.9	1,240.6
RICE - Natural Gas	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	0.0	0.0	0.0
Solar + Storage	0.0	0.0	0.0
Solar + Wind	0.0	0.0	0.0
Steam - Coal	0.0	0.0	0.0
Steam - Natural Gas	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0
Wind	0.0	0.0	0.0
Wind + Storage	0.0	0.0	0.0
Total	7,951.4	7,498.8	5,566.4

The application phase for TC2 opened on June 20, 2024, coincident with the close of phase I of transition cycle 1. The application phase required all active projects in queues AG2 and AH1 to reapply under the new rules. The application phase of TC2 was open for 180 days, and closed on December 17, 2024.

There were 1,347 projects (103,151.7 MW) eligible to resubmit for evaluation in TC2. Of those 1,347 eligible projects, 550 projects (50,023.2 MW) resubmitted and are now being evaluated in TC2. Of the 1,347 eligible projects, 797 projects (53,155.5 MW) did not resubmit, and were withdrawn from the queue.

The TC2 application review stage began at the close of the application phase. PJM reviewed the submissions for required data and deposits and built the models required for the TC2 system impact studies. The TC2 application review stage completed on July 6, 2025.

On October 31, 2025, PJM completed the phase I system impact study for transition cycle 2 (TC2). Developers had 30 days (until December 2, 2025) to decide whether to proceed with their new service requests into the next study phase of TC2 or to withdraw their projects. Continuing with phase II required developers to meet the decision point I requirements (including additional readiness deposits and proof of site control).[86]

On December 3, 2025, PJM began the phase II system impact study process for TC2. The phase II system impact study process is scheduled for 181 days, and is set to close on June 1, 2026.

Planned Generation Additions

TC2 is comprised of 647 proposed generation projects. TC2 includes 550 projects submitted during the TC2 window, and 97 projects submitted through the RRI window. Those projects make up 78,451.4 MW. On December 31, 2025, all projects in TC2 were either in the status of active or were withdrawn from the cycle. Table 12-67 shows each status by unit type. Of the 78,451.4 MW in TC2, 30,542.4 MW (38.9 percent) were active and 47,909.0 MW (61.1 percent) were withdrawn. Of the 30,542.4 MW in the status of active, 11,849.3 MW (38.8 percent) are solar projects, 468.4 MW (1.5 percent) are wind projects, and 6,230.0 MW (20.4 percent) are battery projects.

86 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 03 (September 25, 2025) for a complete list of all readiness requirements.

Table 12-67 Transition cycle 2 and RRI project status (MW) by unit type: December 31, 2025

	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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	6,230.0	6,962.6	763.0	0.0	0.0	5.0	0.0	0.0	1,502.8	0.0	0.0	0.0	11,849.3	2,751.3	0.0	0.0	0.0	0.0	10.1	468.4	0.0	30,542.4
Withdrawn	13,515.9	13,723.6	0.0	0.0	0.0	0.0	0.0	19.3	0.0	0.0	0.0	0.0	13,677.6	3,465.0	10.0	0.0	0.0	0.0	3.2	3,494.4	0.0	47,909.0
Total	19,745.9	20,686.2	763.0	0.0	0.0	5.0	0.0	19.3	1,502.8	0.0	0.0	0.0	25,526.9	6,216.3	10.0	0.0	0.0	0.0	13.3	3,962.8	0.0	78,451.4

Table 12-68 shows the projects in TC2 with a status of active or under construction, by unit type, and control zone. As of December 31, 2025, 30,542.4 MW were in TC2 for construction through 2031. Table 12-68 also shows the planned retirements for each zone.

Table 12-68 Transition cycle 2 and RRI totals for projects (active and under construction) by LDA, control zone and unit type (MW): December 31, 2025

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total Queue Capacity	Planned Retirements
EMAAC	ACEC	300.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	84.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	384.0	175.1
	DPL	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	102.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	122.2	16.4
	JCPLC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	117.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	117.9	65.0
	PECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	760.0
	PSEG	0.0	293.2	0.0	0.0	0.0	0.0	0.0	0.0	256.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	550.0	0.0
	REC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EMAAC Total	320.0	293.2	0.0	0.0	0.0	0.0	0.0	0.0	256.8	0.0	0.0	0.0	304.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,174.1	1,016.5
SWMAAC	BGE	635.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	55.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	690.0	1,975.0
	PEPCO	0.0	53.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	110.0	670.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	833.7	0.0
	SWMAAC Total	635.0	53.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	165.0	670.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,523.7	1,975.0
WMAAC	MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	859.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	859.0	0.0
	PE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	364.0	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	389.0	0.0
	PPL	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	48.0	0.0
	WMAAC Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	859.0	0.0	0.0	0.0	412.0	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,296.0	0.0
Non-MAAC	AEP	1,503.0	72.0	752.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,847.3	630.0	0.0	0.0	0.0	0.0	10.1	0.0	0.0	6,814.4	2,620.0
	AMPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	APS	390.0	2,370.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	614.9	69.0	0.0	0.0	0.0	0.0	0.0	468.4	0.0	3,912.6	0.0
	ATSI	150.0	1,815.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	170.0	110.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,245.7	0.0
	COMED	1,187.0	0.0	11.0	0.0	0.0	5.0	0.0	0.0	387.0	0.0	0.0	0.0	2,205.0	359.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,154.8	2,607.9
	DAY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DUKE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DLCO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.7	0.0
	DOM	2,045.0	1,572.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,112.8	824.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,553.8	0.0
	EKPC	0.0	786.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	615.0	63.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,464.3	116.0
	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	398.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	398.5	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	0.0	0.0	0.0
	Non-MAAC Total	5,275.0	6,616.0	763.0	0.0	0.0	5.0	0.0	0.0	387.0	0.0	0.0	0.0	10,968.2	2,056.1	0.0	0.0	0.0	0.0	10.1	468.4	0.0	26,548.7	5,343.9
Total		6,230.0	6,962.6	763.0	0.0	0.0	5.0	0.0	0.0	1,502.8	0.0	0.0	0.0	11,849.3	2,751.3	0.0	0.0	0.0	0.0	10.1	468.4	0.0	30,542.4	8,335.4

Table 12-69 shows that on December 31, 2025 there were 30,542.4 MW, on an energy basis, of which 22,330.0 MW are on a capacity basis that requested CIRs, in TC2 in the status of active or under construction. Table 12-69 also shows the total capacity MW adjusted for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 22,330.0 MW, on a capacity basis that requested CIRs in TC2 in the status of active or under construction, 10,233.0 MW (45.8 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 7,392.9 MW, on a capacity basis that requested CIRs, of thermal projects (including combined cycle and CT natural gas projects) requested in TC2 in the status of active, 5,374.8 MW (72.7 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 6,507.0 MW, on a capacity basis that requested CIRs, of solar projects requested in TC2 in the status of active or under construction, 520.6 MW (8.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 4,981.3 MW, on a capacity basis that requested CIRs, of battery projects requested in TC2 in the status of active or under construction, 2,889.2 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 8,635.8 MW, on a capacity basis that requested CIRs, of renewable projects requested in TC2 in the status of active or under construction, 717.3 MW (8.3 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Table 12-69 Transition cycle 2 and RRI totals for projects (active and under construction) by unit type adjusted for ELCC derates (MW): December 31, 2025

	Energy (MW)	Capacity (MW)	
Unit Type	Total	Total	ELCC Adjusted
Battery	6,230.0	4,981.3	2,889.2
CC	6,962.6	6,654.9	4,924.6
CT - Natural Gas	763.0	738.0	450.2
CT - Oil	0.0	0.0	0.0
CT - Other	0.0	0.0	0.0
Fuel Cell	5.0	5.0	4.6
Hydro - Pumped Storage	0.0	0.0	0.0
Hydro - Run of River	0.0	0.0	0.0
Nuclear	1,502.8	1,305.9	1,240.6
RICE - Natural Gas	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	11,849.3	6,507.0	520.6
Solar + Storage	2,751.3	2,048.6	163.9
Solar + Wind	0.0	0.0	0.0
Steam - Coal	0.0	0.0	0.0
Steam - Natural Gas	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0
Steam - Other	10.1	9.1	6.5
Wind	468.4	80.2	32.9
Wind + Storage	0.0	0.0	0.0
Total	30,542.4	22,330.0	10,233.0

Withdrawn Projects

Table 12-70 shows the status of all TC2 projects as they have progressed through the cycle process. Of the 647 projects included in TC2, 46 projects (7.1 percent of all projects and 21.7 percent of the total MW) were withdrawn as part of the RRI evaluation, 51 projects (7.9 percent of all projects and 6.6 percent of the total MW) were withdrawn prior to the beginning of phase I, and 269 projects (41.6 percent of all projects and 32.8 percent of the total MW) were withdrawn during phase I or decision point I. On December 31, 2025, 281 projects (43.4 percent of all projects and 38.9 percent of the total MW) remain active in TC2.

Table 12-70 Transition cycle 2 and RRI status: December 31, 2025

	Number of Projects	Percent of Projects	MW Energy	Percent of MW Energy
Transition cycle 2 approved projects	647	100.0%	78,451.4	100.0%
RRI projects not selected	46	7.1%	17,014.8	21.7%
Withdrawn prior to start of phase I	51	7.9%	5,201.1	6.6%
Withdrawn during phase I or decision point I	269	41.6%	25,693.0	32.8%
Withdrawn during phase II or decision point II	0	0.0%	0.0	0.0%
Active as of December 31, 2025	281	43.4%	30,542.4	38.9%
In final agreement stage as of December 31, 2025	0	0.0%	0.0	0.0%
Under construction	0	0.0%	0.0	0.0%
In Service	0	0.0%	0.0	0.0%

Table 12-71 shows 78,451.4 MW have entered TC2. Table 12-71 presents totals by fuel type and projected in service date as of December 31, 2025. Of the 78,451.4 MW to enter TC2, 21,449.2 MW (27.3 percent) were thermal units.

Table 12-71 Transition cycle 2 and RRI total (MW Energy) by unit type and projected in service year: December 31, 2025

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	107.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	399.9	33.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	539.9
2021	4,357.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3	0.0	0.0	0.0	0.0	5,417.5	1,715.3	10.0	0.0	0.0	0.0	0.0	2,727.6	0.0	14,232.7
2022	230.0	0.0	52.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	292.0	275.0	0.0	0.0	0.0	0.0	0.0	147.0	0.0	996.0
2023	683.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,162.8	887.3	0.0	0.0	0.0	0.0	10.1	0.0	0.0	2,743.1
2024	2,300.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,949.5	320.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,569.5
2025	10,493.9	13,805.6	0.0	0.0	0.0	5.0	0.0	14.0	0.0	0.0	0.0	0.0	11,735.2	2,985.7	0.0	0.0	0.0	0.0	3.2	1,088.2	0.0	40,130.8
2026	0.0	2,119.0	700.0	0.0	0.0	0.0	0.0	0.0	88.0	0.0	0.0	0.0	570.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,477.0
2027	0.0	167.6	0.0	0.0	0.0	0.0	0.0	0.0	1,245.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,413.4
2028	0.0	20.0	11.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.0
2029	1,575.0	127.2	0.0	0.0	0.0	0.0	0.0	0.0	169.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,871.2
2030	0.0	2,894.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,894.9
2031	0.0	1,552.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,552.0
Total	19,745.9	20,686.2	763.0	0.0	0.0	5.0	0.0	19.3	1,502.8	0.0	0.0	0.0	25,526.9	6,216.3	10.0	0.0	0.0	0.0	13.3	3,962.8	0.0	78,451.4

Table 12-72 shows there were 30,542.4 MW in TC2 in the status of active or under construction as of December 31, 2025. Table 12-72 presents totals by fuel type and projected in service date. Of the 30,542.4 MW, 7,725.6 MW (25.3 percent) are thermal units.

Table 12-72 Transition cycle 2 and RRI total (MW Energy) by unit type and projected in service year (active and under construction): December 31, 2025

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	74.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	74.6
2022	230.0	0.0	52.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	292.0	275.0	0.0	0.0	0.0	0.0	0.0	147.0	0.0	996.0
2023	683.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,162.8	887.3	0.0	0.0	0.0	0.0	10.1	0.0	0.0	2,743.1
2024	2,300.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,949.5	320.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,569.5
2025	1,442.0	82.0	0.0	0.0	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	3,800.4	1,269.0	0.0	0.0	0.0	0.0	0.0	321.4	0.0	6,919.8
2026	0.0	2,119.0	700.0	0.0	0.0	0.0	0.0	0.0	88.0	0.0	0.0	0.0	570.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,477.0
2027	0.0	167.6	0.0	0.0	0.0	0.0	0.0	0.0	1,245.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,413.4
2028	0.0	20.0	11.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.0
2029	1,575.0	127.2	0.0	0.0	0.0	0.0	0.0	0.0	169.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,871.2
2030	0.0	2,894.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,894.9
2031	0.0	1,552.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,552.0
Total	6,230.0	6,962.6	763.0	0.0	0.0	5.0	0.0	0.0	1,502.8	0.0	0.0	0.0	11,849.3	2,751.3	0.0	0.0	0.0	0.0	10.1	468.4	0.0	30,542.4

Table 12-73 shows there were 47,909.0 MW withdrawn from TC2. Table 12-73 presents totals by fuel type and projected in service date. Of the 47,909.0 MW withdrawn from TC2, 13,723.6 MW (28.6 percent) were thermal units.

Table 12-73 Transition cycle 2 and RRI total (MW Energy) by unit type and projected in service year (withdrawn): December 31, 2025

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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	107.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	399.9	33.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	539.9
2021	4,357.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3	0.0	0.0	0.0	0.0	5,342.9	1,715.3	10.0	0.0	0.0	0.0	0.0	2,727.6	0.0	14,158.1
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	9,051.9	13,723.6	0.0	0.0	0.0	0.0	0.0	14.0	0.0	0.0	0.0	0.0	7,934.8	1,716.7	0.0	0.0	0.0	0.0	3.2	766.8	0.0	33,211.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	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	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	13,515.9	13,723.6	0.0	0.0	0.0	0.0	0.0	19.3	0.0	0.0	0.0	0.0	13,677.6	3,465.0	10.0	0.0	0.0	0.0	3.2	3,494.4	0.0	47,909.0

Analysis by Fuel Group

Table 12-74 shows the number of projects that entered TC2 by year and by fuel group. The fuel groups are nuclear units, renewable units (including hydro run of river, solar and wind units (including renewable solar and wind hybrids), storage units (including battery and pumped storage hydro units), thermal units (including combined cycle, CT natural gas and oil, RICE natural gas and oil and steam coal, natural gas and oil) and other units (all other fuels). The 647 projects submitted to TC2 were made up of 390 renewable projects (60.3 percent), 189 storage projects (29.2 percent), 58 thermal projects (9.0 percent), five nuclear projects (0.8 percent) and five other fuel projects (0.8 percent).

Table 12-74 Transition cycle 2 and RRI number of projects by fuel group: December 31, 2025

	Fuel Group										
Year Entered	Nuclear	Percent Nuclear	Renewable	Percent Renewable	Storage	Percent Storage	Thermal	Percent Thermal	Other	Percent Other	Total
2018	0	0.0%	1	100.0%	0	0.0%	0	0.0%	0	0.0%	1
2019	0	0.0%	2	100.0%	0	0.0%	0	0.0%	0	0.0%	2
2020	0	0.0%	12	70.6%	4	23.5%	0	0.0%	1	5.9%	17
2021	0	0.0%	237	68.9%	100	29.1%	4	1.2%	3	0.9%	344
2022	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0
2023	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0
2024	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0
2025	5	1.8%	138	48.8%	85	30.0%	54	19.1%	1	0.4%	283
Total	5	0.8%	390	60.3%	189	29.2%	58	9.0%	5	0.8%	647

As of December 31, 2025, there were 281 projects in TC2 in the status of active or under construction. Those 281 projects consisted of 172 renewable projects (61.2 percent of all projects and 49.3 percent of the nameplate MW), 64 storage projects (22.8 percent of all projects and 20.4 percent of the nameplate MW), 37 thermal projects (13.2 percent of all projects and 25.3 percent of the nameplate MW), five nuclear projects (1.8 percent of all projects and 4.9 percent of the nameplate MW) and three other fuel type projects (1.1 percent of all projects and .05 percent of the nameplate MW) (Table 12-75).

Table 12-75 Transition cycle 2 and RRI details by fuel group: December 31, 2025

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	5	1.8%	1,502.8	4.9%
Renewable	172	61.2%	15,068.9	49.3%
Storage	64	22.8%	6,230.0	20.4%
Thermal	37	13.2%	7,725.6	25.3%
Other	3	1.1%	15.1	0.0%
Total	281	100.0%	30,542.4	100.0%

Analysis by Unit Type and Project Classification

Table 12-76 shows the status of all new generation projects in TC2 by unit type and project classification as of December 31, 2025. Project classification is defined as either new generation or an uprate in which existing resources are modified to increase the economic maximum generation capability. There were 647 projects, representing 78,451.4 MW, entered into TC2. Of those, 647 projects, 366 projects, representing 47,909.0 MW (61.1 percent of the MW) withdrew prior to completion.

A total of 425 projects have been classified as new generation and 222 projects have been classified as upgrades. Natural gas, wind, solar and renewable hybrid projects (including solar + storage, solar + wind and wind + storage) have accounted for 445 projects (68.8 percent) of all 647 generation projects to enter TC2.

Table 12-76 Transition Cycle 2 and RRI status of all generation projects: December 31, 2025

		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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	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	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Under Construction	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	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	67	14	0	0	0	0	0	2	0	0	0	0	129	32	1	0	0	0	1	7	0	253
	Upgrade	58	7	0	0	1	0	0	0	0	0	0	0	41	5	0	0	0	0	0	1	0	113
Active	New Generation	35	5	1	0	0	1	0	0	1	0	0	0	105	20	0	0	0	0	1	3	0	172
	Upgrade	29	19	11	0	0	0	0	0	4	0	0	0	42	1	0	1	0	0	1	1	0	109
Total Projects	New Generation	102	19	1	0	0	1	0	2	1	0	0	0	234	52	1	0	0	0	2	10	0	425
	Upgrade	87	26	11	0	1	0	0	0	4	0	0	0	83	6	0	1	0	0	1	2	0	222

Table 12-77 shows the totals in Table 12-76 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, 33.3 percent of all battery projects in TC2 classified as upgrades were active and 66.7 percent of battery projects classified as upgrades were withdrawn from TC2 as of December 31, 2025.

Table 12-77 Transition Cycle 2 and RRI status of all generation projects as a percent of total projects by classification: December 31, 2025

		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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	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%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Under Construction	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%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Withdrawn	New Generation	65.7%	73.7%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	55.1%	61.5%	100.0%	0.0%	0.0%	0.0%	50.0%	70.0%	0.0%	59.5%
	Upgrade	66.7%	26.9%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	49.4%	83.3%	0.0%	0.0%	0.0%	0.0%	0.0%	50.0%	0.0%	50.9%
Active	New Generation	34.3%	26.3%	100.0%	0.0%	0.0%	100.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	44.9%	38.5%	0.0%	0.0%	0.0%	0.0%	50.0%	30.0%	0.0%	40.5%
	Upgrade	33.3%	73.1%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	50.6%	16.7%	0.0%	100.0%	0.0%	0.0%	100.0%	50.0%	0.0%	49.1%

Table 12-78 shows the total MW of projects in TC2 by unit type and project classification. For example, the 67 new generation battery projects that have been withdrawn from TC2 as of December 31, 2025, (as shown in Table 12-76) constitute 10,075.1 MW. The 129 new generation solar projects that have been withdrawn in the same time period constitute 10,796.9 MW.

Table 12-78 Transition cycle 2 and RRI status of all generation (MW) projects: December 31, 2025

		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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Under Construction	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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	10,075.1	13,492.2	0.0	0.0	0.0	0.0	0.0	19.3	0.0	0.0	0.0	0.0	10,796.9	3,097.6	10.0	0.0	0.0	0.0	3.2	3,426.4	0.0	40,920.7
	Upgrade	3,440.8	231.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,880.7	367.4	0.0	0.0	0.0	0.0	0.0	68.0	0.0	6,988.3
Active	New Generation	4,698.6	5,738.0	700.0	0.0	0.0	5.0	0.0	0.0	859.0	0.0	0.0	0.0	9,833.3	2,661.3	0.0	0.0	0.0	0.0	10.1	468.4	0.0	24,973.6
	Upgrade	1,531.4	1,224.6	63.0	0.0	0.0	0.0	0.0	0.0	643.8	0.0	0.0	0.0	2,016.0	90.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,568.8
Total Projects	New Generation	14,773.7	19,230.2	700.0	0.0	0.0	5.0	0.0	19.3	859.0	0.0	0.0	0.0	20,630.2	5,758.9	10.0	0.0	0.0	0.0	13.3	3,894.8	0.0	65,894.3
	Upgrade	4,972.2	1,456.0	63.0	0.0	0.0	0.0	0.0	0.0	643.8	0.0	0.0	0.0	4,896.7	457.4	0.0	0.0	0.0	0.0	0.0	68.0	0.0	12,557.1

Table 12-79 shows the MW totals in Table 12-78 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, 30.8 percent of all battery project MW in TC2 classified as upgrades were active and 69.2 percent of battery project MW classified as upgrades were withdrawn from TC2 as of December 31, 2025.

Table 12-79 Transition cycle 2 and RRI status of all generation projects as percent of total MW in project classification: December 31, 2025

		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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	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%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Under Construction	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%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Withdrawn	New Generation	68.2%	70.2%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	52.3%	53.8%	100.0%	0.0%	0.0%	0.0%	24.1%	88.0%	0.0%	62.1%
	Upgrade	69.2%	15.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	58.8%	80.3%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	55.7%
Active	New Generation	31.8%	29.8%	100.0%	0.0%	0.0%	100.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	47.7%	46.2%	0.0%	0.0%	0.0%	0.0%	75.9%	12.0%	0.0%	37.9%
	Upgrade	30.8%	84.1%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	41.2%	19.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	44.3%

Cycle Process Totals[87]

On December 31, 2025, there were 959 proposed generation projects in the new services cycle process queues. Those projects make up 119,101.5 MW. On December 31, 2025, all projects in the cycle process queues were either in the status of active or were withdrawn. Table 12-80 shows each status by unit type. Of the 119,101.5 MW in the cycle process queues, 45,439.7 MW (38.2 percent) were active and 73,661.8 MW (61.8 percent) were withdrawn. Of the 45,439.7 MW in the status of active, 19,579.4 MW (43.1 percent) were solar projects, 4,458.3 MW (9.8 percent) were wind projects, and 7,987.2 MW (17.6 percent) were battery projects.

Table 12-80 All cycles (TC1, TC2 and RRI) project status (MW) by unit type: December 31, 2025

	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	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	7,987.2	6,962.6	1,332.0	0.0	0.0	5.0	0.0	0.0	1,502.8	0.0	0.0	0.0	19,579.4	3,602.3	0.0	0.0	0.0	0.0	10.1	4,458.3	0.0	45,439.7
Withdrawn	18,041.1	13,723.6	0.0	0.0	0.0	0.0	0.0	19.3	0.0	0.0	0.0	0.0	26,877.4	6,722.2	209.0	0.0	0.0	0.0	3.2	8,066.1	0.0	73,661.8
Total	26,028.3	20,686.2	1,332.0	0.0	0.0	5.0	0.0	19.3	1,502.8	0.0	0.0	0.0	46,456.9	10,324.4	209.0	0.0	0.0	0.0	13.3	12,524.4	0.0	119,101.5

Table 12-81 shows that on December 31, 2025 there were 45,439.7 MW, on an energy basis, of which 29,615.6 MW are on a capacity basis that requested CIRs, in cycle process queues in the status of active or under construction. Table 12-81 also shows the total capacity MW adjusted for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 29,615.6 MW, on a capacity basis that requested CIRs in the cycle process queues in the status of active or under construction, 12,134.4 MW (41.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 7,961.1 MW, on a capacity basis that requested CIRs, of thermal projects (including combined cycle and CT natural gas projects) requested in cycle process queues in the status of active, 5,721.9 MW (71.9 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 10,344.9 MW, on a capacity basis that requested CIRs, of solar projects requested in cycle process queues in the status of active or under construction, 827.6 MW (8.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 6,334.6 MW, on a capacity basis that requested CIRs, of battery projects requested in cycle process queues in the status of active or under construction, 3,674.1 MW (58.0 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

Of the 13,999.1 MW, on a capacity basis that requested CIRs, of renewable projects requested in cycle process queues in the status of active or under construction, 1,486.7 MW (10.6 percent) are expected to go into service after accounting for the ELCC derate factors using the class ratings for the 2027/2028 Base Residual Auction.

87 As of December 31, 2025, the cycle process totals include those projects included in TC1 and TC2.

Table 12-81 All cycles (TC1, TC2 and RRI) projects (active and under construction) by unit type adjusted for ELCC derates (MW): December 31, 2025

	Energy (MW)	Capacity (MW)	
Unit Type	Total	Total	ELCC Adjusted
Battery	7,987.2	6,334.6	3,674.1
CC	6,962.6	6,654.9	4,924.6
CT - Natural Gas	1,332.0	1,307.0	797.3
CT - Oil	0.0	0.0	0.0
CT - Other	0.0	0.0	0.0
Fuel Cell	5.0	5.0	4.6
Hydro - Pumped Storage	0.0	0.0	0.0
Hydro - Run of River	0.0	0.0	0.0
Nuclear	1,502.8	1,305.9	1,240.6
RICE - Natural Gas	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	19,579.4	10,344.9	827.6
Solar + Storage	3,602.3	2,542.9	203.4
Solar + Wind	0.0	0.0	0.0
Steam - Coal	0.0	0.0	0.0
Steam - Natural Gas	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0
Steam - Other	10.1	9.1	6.5
Wind	4,458.3	1,111.3	455.6
Wind + Storage	0.0	0.0	0.0
Total	45,439.7	29,615.6	12,134.4

Surplus Interconnection Service (SIS)

FERC Order 845 required transmission providers to create a process for interconnection customers to use surplus interconnection service at existing points of interconnection.[88] Surplus interconnection service is defined as "any unneeded portion of interconnection service established in a large generator interconnection agreement (LGIA), such that if surplus interconnection service is utilized, the total amount of interconnection service at the point of interconnection would remain the same."[89] For example, a developer may request SIS to add a solar facility at the location of an existing battery storage facility. In this example, the battery storage facility operates at night only, while the solar facility operates during the day. The net output at the point of interconnection would never exceed the maximum facility output as studied for the existing battery storage facility's generation interconnection agreement.

Surplus interconnection service requests can be made by a project developer or one of its affiliates whose generating facility is already interconnected to the PJM transmission system or has executed (or requested to file unexecuted) an interconnection service agreement (ISA) or generation interconnection agreement (GIA), or by an unaffiliated project developer. The project developer, or one of its affiliates, has priority to use the service. However, if a project developer or affiliate does not submit a request for SIS, an unaffiliated project developer may request service. Under the SIS process, projects that do not trigger transmission system upgrades qualify for expedited review by PJM outside the interconnection queue. In order for a SIS request to be approved, no new network upgrades must be required to accommodate the request.[90]

If surplus interconnection service is requested on a generating facility that is an energy only resource, the generating facility requesting the SIS will also be an energy only resource. If surplus interconnection service is requested on a generating facility that is a capacity resource, the generating facility requesting surplus interconnection service may be an energy resource or a capacity resource, not to exceed the amount of CIRs established in the ISA or GIA. Requests for SIS are not posted publicly by PJM.

Interconnection Costs for New Projects

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.[91] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. As part of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of interconnecting projects in the queue. Interconnection requests are for energy only resources and for capacity resources.

Interconnecting capacity resources must meet a higher standard than energy only resources. For interconnecting capacity resources, PJM performs deliverability studies that ensure that the energy from the proposed generator can be reliably provided to the PJM region. Deliverability studies identify network upgrades needed to ensure that the transmission system is capable of delivering the aggregate system generating capacity at peak load, including the new resource, with all firm transmission service modeled.[92]

88 See *Reform of Generator Interconnection Procedures and Agreements, Order No. 845*, 163 FERC ¶ 61,043 (2018).
89 Id. At Pg. 373
90 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 03 (September 25, 2025).
91 See OATT Parts IV & VI.
92 See "PJM Manual 14B: PJM Regional Transmission Planning Process," Rev. 58 (December 17, 2025).

The interconnection service agreement identifies the transmission modifications needed to maintain the reliability of the transmission system as a result of a new service request. These identified modifications are known as network upgrades. In general, there are fewer network upgrades associated with energy only resources, as energy only resources are not required to be deliverable to the entire PJM footprint.[93] On December 31, 2025, there were 2,087 active network transmission upgrades. If a project is withdrawn from the queue, the network upgrades associated with that project are no longer required, unless it is required to support another queue project.

While not all projects in the queue require network upgrades, the number of planned network transmission upgrades is strongly correlated with the number of active projects in the queue. The number of planned network upgrades is also strongly correlated with the number of new generation projects requesting interconnection as a capacity resource. After the execution of an interconnection service agreement, queue projects become part of the RTEP study and the costs of any upgrade later necessary to preserve their Capacity Interconnection Rights are included as part of the overall transmission system costs paid by all transmission customers.

The system impact study is a detailed system analysis performed for new service requests that tests deliverability under peak load conditions and light load conditions. The system impact study identifies system constraints caused by the request and the local upgrades and network upgrades required to solve those constraints. The system impact study includes power flow analysis and short circuit analysis. The power flow analysis includes expected output level from the new resource under summer peak and light load system conditions.[94] PJM's recent improvements to the deliverability analyses reflect more accurate information about the expected performance of intermittent resources, by type of resource (solar fixed, solar tracking, onshore wind and offshore wind), by season (summer, winter and light load) and by region (PJM West, Mid-Atlantic and Dominion), under each of these system conditions. Those modifications are necessary to accurately reflect the expected output of intermittent resources under various seasons and system conditions as the penetration and role of intermittents in PJM increases.[95] For example, the expected output of onshore wind varies from its maximum facility output to zero, depending on weather conditions, and the expected output levels are used for each system load condition.[96]

Capacity resources receive Capacity Interconnection Rights (CIRs) based on the deliverable MW which result from a combination of upgrades paid for by each project and existing system capability. Intermittent resources also require CIRs. The level of CIRs required for intermittent resources has been significantly understated because the required CIRs have been based on the derated capacity value of intermittents rather than the maximum energy injections required to achieve the derated value.

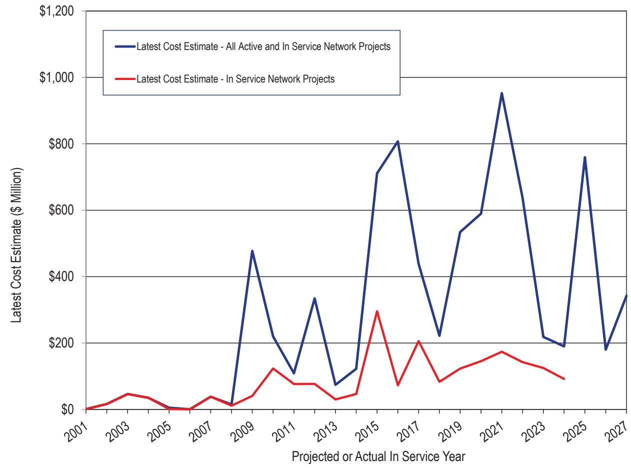
After a lengthy stakeholder process, on April 7, 2023, FERC approved updates to PJM's ELCC method that cap the level of an intermittent generator's output used to calculate the generator's reliability contribution (ELCC derated MW) at the generator's CIR level.[97] Rules prior to the FERC order allowed generation at a level greater than the CIR value, and that was therefore not deliverable, to be inappropriately included in the ELCC calculations. For example, if a 100 MW solar resource has CIRs of 60 MW, generation in excess of 60 MW will not be included in the ELCC calculations under the updated rules. Prior to the update, the generation in excess of the CIR level was included, overstating the ELCC ratings and reliability contribution of ELCC resources. The overstatement of intermittent capacity has inefficiently suppressed capacity market clearing prices.[98] [99] In order to retain the prior, incorrectly calculated ELCC values, existing intermittent generating units are required to increase their CIRs by going through an expedited queue process. The ELCC updates established a transitional period during which intermittent generators can be awarded temporary increases in their CIRs based on the availability of transmission system capability.[100] PJM expects a transitional period of four years, beginning

93 See "PJM Manual 14G: Generation Interconnection Requests," Rev. 8 (July 26, 2023).
94 Winter peak load is included in the generation deliverability powerflow analysis during the RTEP baseline reliability analysis, but is not currently performed for new interconnection requests. The light load analysis ensures generation deliverability during light load conditions, which is defined as 50 percent of the annual peak demand.
95 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 58 (December 17, 2025).
96 See "Generation Deliverability Test Modifications: Light Load, Summer & Winter," presented at January 25, 2023 meeting of the Markets and Reliability Committee <https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20230125/consent-agenda-c---1-generator-deliverability-test-revisions---presentation.ashx>.
97 183 FERC ¶61,009.
98 *See* "Analysis of the 2023/2024 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf>. (October 28, 2022).
99 *See* "Analysis of the 2022/2023 RPM Base Residual Auction—Revised," <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20222023_RPM_BRA_Revised_20230113.pdf> (January 13, 2023).
100 183 FERC ¶61,009 at 31.

with the 2025/2026 Base Residual Auction, to be sufficient time for intermittent resources to reenter the queue and be awarded additional CIRs. New intermittent generators will be required to pay for CIRs consistent with their calculated reliability contribution.

Figure 12-5 shows the latest estimated interconnection costs for new generators (network transmission project cost) by projected and actual in service year for generators that are in service (red line), and for the total of generators in service and still in the queue in active status (blue line). The estimated costs for in service projects (red line) are much lower than the estimated costs that also include all projects in the queue (blue line). The increase in estimated total network upgrade costs for planned projects is a result of the large number of requests in the new services queue and the existing backlog (Figure 12-5). However, as generators withdraw from the queue, the overall network costs decrease. The estimated network upgrade costs for in service projects are much lower. The projected in service dates for network projects are not updated regularly, and therefore, may not be an accurate predictor of when these projects are actually expected to go in service. Figure 12-5 shows a significant level of estimated interconnection costs for resources with projected in service dates as far back as 2008 and a peak for projects with a projected in service date of 2021. Even the costs for projects that are in service are only estimates because PJM does not track final project costs. The final in service costs include only the last estimate provided by PJM before the project went in service. PJM's data collection, management and retention related to transmission spending of all types is inadequate and needs a significant upgrade. The failure to collect data on estimated and final project costs makes it impossible to track transmission project costs for all project types. Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data.

Figure 12-5 Cost estimates of network projects by projected and actual in service year: January 1, 2001 through December 31, 2027



Regional Transmission Expansion Plan (RTEP)[101]

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 Managers approvals. The 24 month planning process is made up of overlapping 18 month planning cycles to identify and develop shorter lead time transmission upgrades

101 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. 58 (December 17, 2025).

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; identify new transmission enhancements that result in economic benefits; and identify economic benefits associated with modification to existing RTEP reliability based enhancements that when modified would relieve one or more economic constraints. The PJM market efficiency analysis is badly flawed and results in concluding there are net benefits when there are not. 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 of the proposed project must reduce congestion on one or more constraints by at least one dollar, meet a ratio threshold of at least 1.25:1 and have an independent cost review, performed by PJM, if expected costs are over $50 million. PJM provides the review of a project with a projected cost of over $50 million using its own staff or outside consultants. PJM presents its findings to the TEAC where PJM's findings are reviewed by the stakeholders. While stakeholders can comment on the findings, PJM makes the final decision about what costs will be used for the purpose of calculating the benefit/cost ratio for the project. 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 concurrently with the long-term proposal window for reliability projects.

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, submitted by an incumbent transmission owner, 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, all submitted by an incumbent transmission owner, 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 accepted proposals to address historical congestion on four identified flowgates. PJM received 96 proposals from 20 entities. Four projects, all submitted by an incumbent transmission owner, 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, submitted by an incumbent transmission owner, 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, submitted by an incumbent transmission owner, was approved by the PJM Board to address the historical congestion on the internal flowgate, and one project, submitted by an incumbent transmission owner, was approved by the

PJM Board to address the historical congestion on one of the interregional flowgates.[102]

The fifth market efficiency cycle was performed for the 2020/2021 RTEP long term window. The 2020/2021 RTEP long term window was open from November 11, 2020, through May 11, 2021. This window accepted proposals to address historical congestion on four internal flowgates. PJM received 24 proposals from seven entities. Four projects, all submitted by an incumbent transmission owner, were approved by the PJM Board.

The sixth market efficiency cycle was performed during the 2022/2023 RTEP long term window. The 2022/2023 RTEP long term window was delayed until the reliability violations for the 2022 Window 3 (Dominion data center loads) could be addressed. On November 21, 2023, PJM requested that the Commission grant a waiver to extend the time for PJM to complete its annual review of the benefit/cost analysis associated with the market efficiency cycle.[103] PJM requested the waiver to remain in effect until PJM completes its 2023 annual review no later than the end of the second quarter of 2024. On December 21, 2023, The Commission approved the waiver request.[104] In January 2024, PJM completed updating the 2022/2023 market efficiency base case to include the solution selected from the 2022 Window 3. No flowgates experienced historical congestion that required an open window.

In February 2024, PJM completed the 2024/2025 market efficiency base case. In May 2024, PJM posted the 2024/2025 Market Efficiency planning assumptions. The long term market efficiency window opened on April 11, 2025, and closed on June 10, 2025. This window accepted proposals to address historical congestion on three identified flowgates (Museville-Smith Mountain 128 kV in AEP, West Point-Lanexa 115 kV in DOM and Garrett-Garrett Tap 115 kV in PN-APS). PJM received 14 proposals from five entities. Two projects, submitted by incumbent transmission owners, were selected as the preferred solutions.[105] These projects will be presented to the PJM Board for approval in the first quarter of 2026. There were no projects selected for acceleration in the 2024/2025 market efficiency window.

102 No proposals effectively resolved the congestion on two of the three identified interregional market efficiency flowgates.
103 See *PJM Interconnection, L.L.C*, Docket No. ER24-477-000 (November 21, 2023).
104 185 FERC ¶61,212.
105 One of the three identified congestion drivers included in the market efficiency window (Garrett-Garrett Tap 115 kV) was addressed in the 2025 RTEP Window 1.

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. Depending on the type of project being evaluated PJM may measure 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. There are significant issues with PJM's definition of benefits. If done correctly and if FTRs/ARRs returned 100 percent of congestion to load, the benefit/cost analysis would include the total net change in production costs and would not include congestion. The change in production costs correctly measures the changes in cost to load that result from a project.

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 basis for load projections depends primarily on the projections of data center load which are highly uncertain and for which PJM has limited information about exact location and specifications. As made clear in the queue analysis, the actual addition of generation resources by type and location is also highly uncertain. The level of uncertainty makes the value of efficiency projects speculative and not an appropriate basis for investment in transmission projects.

The definition of the energy benefit analysis 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. 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 but, inexplicably, only for those zones where the project reduces the load payments and ignoring zones where the project increases 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 again only for those zones where the project reduces the load energy payments and ignoring zones where the project increases load payments.

In both the regional and subregional analysis, changes in zonal load energy payments subtract the estimated value of any Auction Revenue Rights (ARR) that sink in that zone. An increase in ARR revenues that result from a project would reduce the benefits of that project to load. If done correctly and if ARRs returned 100 percent of congestion to load, the changes in load payments would equal the change in production costs. However, the calculated ARR credits in the benefit/cost analysis ignore any increases in ARR MW and include only the reduction in the estimated CLMP differences. Estimated ARR credits are calculated for each simulated year using the most recent planning year's actual ARR MW combined with the simulation's CLMP differences between ARR source and sink points. ARR MW are not adjusted to reflect any increase in ARR MW created by the RTEP upgrade. This means that the reduction in the ARR offset value is too large, the reduction in load payments is overstated, and the value of the proposed project is artificially increased.

The Reliability Pricing Model (RPM) Benefit analysis uses the RPM solution software, with and without the proposed RTEP project, using a set of estimated capacity offers. The basis for the estimated offers is not clear. The relevance of estimated offers in the current capacity market conditions is not clear. The basis for load projections depends primarily on the projections of data center load which are highly uncertain and for which PJM has limited information about exact location and specifications.

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. As with the miscalculation of the congestion impacts in the energy market, this approach overstates the benefits.

The difference in the benefits calculation used in the regional and subregional benefit/cost threshold tests is related to how the direct costs of the transmission projects 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 allocation will be incorrect to the extent that the benefits calculations are incorrect.

There are significant issues with PJM's benefit/cost analysis. The current rules governing benefit/cost analysis of competing transmission projects do not correctly measure the relative costs and benefits of transmission projects. PJM measures benefits as reductions in estimated load charges and production costs in the energy market and reductions in estimated load capacity payments in the capacity market, but PJM's analysis ignores any increases in costs. This means that PJM's benefit/cost analysis systematically overstates the benefits of transmission projects. ARR MW allocations are not adjusted to reflect any potential changes in ARR MW that result from the RTEP upgrade. This means that the reduction in the ARR offset value is too large, the ARR offset is too small, and the result is to artificially increase the value of the proposed project. The correct metric is the change in production costs. In addition, the current rules do not account for the fact that the benefits of projects are uncertain and highly sensitive to the modeling assumptions used, or for the fact that the project costs are nonbinding estimates, are not subject to cost caps and may significantly exceed the estimated costs. These flaws have contributed to PJM approving market efficiency projects with forecasted benefits that only appear to, but do not actually exceed the forecasted costs. In addition, there is no after the fact analysis to validate the planning assumptions and there is no data gathered on the actual costs and benefits that would permit such an analysis.

Recent proposals to use storage as a transmission asset (SATA) raises a number of additional concerns about PJM's benefit/cost analysis. Storage is a market asset and should not be owned by transmission owners. PJM should not be evaluating SATA at all without a decision from FERC that SATA is allowable in PJM. At present it is not allowed. PJM's benefit/cost analysis uses a 15 year forecast for purposes of evaluating benefits and costs of traditional transmission assets with an expected useful life of 50 years or more. Using the same 15 year horizon does not make sense for SATA resources with an expected useful life of 10 years or less, depending on use. In addition, there is no basis for assuming anything about the actual use of a transmission storage asset and therefor any imputed benefits. Using a 15 year benefit horizon exaggerates the forecasted benefit stream relative to the stream of benefits that could be produced over the expected useful life relative to traditional transmission assets. Further, the rules for how to account for the actual, and forecasted, revenues and charges for operating the SATA to provide transmission load relief have not been established. Without clear rules on how to allocate operational revenues and costs, and without detailed information about exactly the storage would be used, it is impossible to develop forecasted benefits and/or costs of a SATA project.

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. This is particularly noteworthy for the SATA case in which transmission owners would built market capacity assets under cost of service regulation that competes directly with market assets.

A significant flaw in PJM's benefit/cost analysis is that projected benefits are based on load forecasts which are currently dominated by projected large data center loads that are not verified by PJM and cannot be verified by PJM. That creates a bias towards finding transmission projects beneficial despite the fact that data center loads are imposing transmission costs on other customers as a result.

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

While the IMEP process is a joint effort, PJM and MISO perform their own analysis of benefits to their own system and each uses a different modeling approach and a different metric for determining the benefits of a proposed project. PJM uses the benefit/cost analysis used for its own internal market efficiency projects which will, by definition, overstate project benefits by ignoring areas where energy costs are increased. MISO, on the other hand, measures benefits as changes in

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

projected system wide production cost caused by the project. The use of different approaches to measuring benefits is an issue when studying potential benefits of projects in a joint effort, and when using the defined benefits to allocate the costs of IMEP projects to each RTO. PJM's approach will over allocate the costs of IMEP projects to PJM members and under allocate costs to MISO members.

No interregional constraints were identified in either PJM's or MISO's regional processes. Therefore, an IMEP study was not required during the 2020/2021 IMEP cycle. No interregional constraints were identified in either PJM or MISO's regional processes. Therefore, an IMEP study was not required during the 2022/2023 IMEP cycle.

PJM and MISO began coordinating on interregional congestion issues to identify potential constraints to address in the 2024/2025 IMEP cycle. The joint regional planning committee (JRPC) decided to not initiate a coordinated system plan in 2025, and will instead prioritize the interregional transfer capability study (ITCS).

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 must have estimated benefits, based on the projected congestion reduction over a four year period that exceed the expected installed capacity cost of the proposed project.[107] [108] The TMEP process calculates congestion and assigns congestion costs to load but fails to account for the offsetting value of ARRs and FTRs. The current rules incorrectly count congestion as a cost to load without accounting for how the congestion dollars are or are not returned to the load through ARRs and FTRs. The correct benefit metric is the change in production costs.

The benefit of a proposed TMEP project is calculated as the value of reducing congestion on the affected constraint over a four year period. PJM and MISO calculate the estimated value of eliminating congestion by calculating the average congestion for the two prior years prior and multiplying by four. Congestion is correctly calculated as the shadow price (difference in CLMP) times the market flow on the line.

The allocation of costs to each RTO for an approved TMEP project will be in proportion to the benefits, as calculated by PJM and MISO, received by that RTO.[109] The proportion of benefits is calculated using the change in the average shadow price of the constraint times the dfax to the affected downstream buses times the MW of load at the buses. This correctly identifies the proportion of the benefits that go to the load that would benefit from the project. Within an RTO, the RTO's share of the cost of the approved project is allocated to each transmission control area in proportion to the benefits received by each transmission control area.

PJM and MISO did not conduct a TMEP study in 2019. As a result of decreases in M2M congestion and the addition of transmission upgrades already in process that affect the top congested historical M2M flowgates, PJM and MISO did not conduct a TMEP study in 2020. PJM and MISO agreed to assess the impact of planned upgrades and congestion using an additional year of market data. As a result, PJM and MISO did not conduct a TMEP study in 2021. The 2022 TMEP study focused on 23 flowgates as potential TMEP projects. Of the 23 initial flowgates, 19 were eliminated due to their relationship with other existing reliability projects already included in PJM's RTEP or MISO's MTEP plans, or the identified congestion was caused by outages.[110] Two projects were eliminated after studies showed that congestion was not persistent in October 2022, and an additional project was eliminated in December 2022 after further studies showed congestion was not persistent, leaving one TMEP project (Powerton - Towerline 138 kV) that was approved for implementation by the PJM Board on February 15, 2023, and by the MISO Board on March

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

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

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

110 See "Interregional Planning Update," presented at the August 9, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220809/item-01---interregional-planning-update.ashx>.

23, 2023.[111] [112] [113] For both 2023 and 2024, the RTOs decided not to initiate a Coordinated System Plan (CSP) study, and to continue to assess the impact of planned upgrades and congestion persistence with additional market data.

PJM and MISO began coordinating on interregional congestion issues to identify potential constraints to address in the 2024/2025 TMEP cycle. The joint regional planning committee (JRPC) decided to not initiate a coordinated system plan in 2025, and will instead prioritize the interregional transfer capability study (ITCS).

The PJM and MISO TMEP process for measuring the projected benefits of a TMEP transmission projects is flawed. The current rules incorrectly count congestion as a cost to load without accounting for how the congestion dollars are or are not returned to the load through ARRs and FTRs. The benefit of a TMEP transmission upgrade should be the expected difference in the total production cost of energy before and after the upgrade to all affected load. This measurement would include the change in expected LMP of all affected load before and after the upgrade, times the MW of load, plus the change in congestion dollars returned to the affected load before and after the upgrade. Congestion revenue returned to load is not a cost to the load, it is a credit against the overpayment of load payments compared to generation credits caused by the transmission constraint. Ignoring the return of congestion from ARRs/FTRs overstates the potential benefits of eliminating congestion through the TMEP upgrades, and ignores the value of smaller upgrades that may not eliminate a constraint, but may reduce the average cost of energy for load.

PJM MISO Interregional Transfer Capability Study (ITCS)

PJM and MISO are performing an Interregional Transfer Capability Study (ITCS).[114] PJM and MISO are coordinating assumptions and models, but will not perform a joint study. The PJM/MISO Interregional Transfer Capability Study is part of PJM's and MISO's strategy to comply with FERC Order No. 1920. The ITCS study appears to mirror PJM's multi driver RTEP process in that it identifies several drivers (efficiency, reliability, transfer needs) for evaluating the value or need for a project, though neither MISO nor PJM provide any specificity as to the exact metrics for the evaluation of the benefits or costs within each identified driver, how the drivers will be weighted or how costs of potential projects should be allocated. The stated purpose of the PJM/MISO Interregional Transfer Capability Study is to allow PJM and MISO to consider needs, assumptions, cost allocations and analysis outside the limits of the existing PJM/MIO JOA/CSP process. The goal of the PJM and MISO ITCS is to identify opportunities to enhance transfer capability on an incremental basis over and above other JOA/CSP based studies.

The ITCS study is intended to look out through 2032. In its ITCS study, PJM plans to use a model that blends MISO planning models for MISO's footprint and a set of PJM's long-term planning assumptions for PJM's footprint. PJM is calling this a blended model. PJM's blended model will use the 2023 Regional Transmission Expansion Plan (RTEP) topology with 2022 RTEP Window 3 solutions, the PJM 2024 official Load Forecast, retirements due to federal regulations and state laws based on the Independent State Agencies Committee (ISAC) workbook and the assumption of sufficient replacement generation or storage for resource adequacy (i.e. to meet 1-in-10 Loss of Load Expectation) selected from interconnection requests and withdrawals. Although it is a feature of many transmission planning studies, simply assuming specific generating assets is not a reasonable way to do transmission planning with significant cost impacts on customers.

Preliminary results from the ITCS study identified various transfer, reliability and economic issues from both PJM and MISO.[115] PJM and MISO presented results and near and long term actions resulting from the ITCS study on June 25, 2025.[116] Interregional constraints were identified in the 2024/2025 PJM and MISO's joint ITCS analysis.[117] MISO opened a proposal window

111 See "Interregional Planning Update," presented at the October 4, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221004/item-01----interregional-planning-update.ashx>.

112 See "PJM-MISO IPSAC," presented at the December 15, 2022 meeting of the PJM-MISO Interregional Planning Stakeholder Advisory Committee <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2022/20221215/ipsac-presentation.ashx>.

113 See "PJM-MISO IPSAC," presented at the December 11, 2023 meeting of the PJM-MISO Interregional Planning Stakeholder Advisory Committee <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2024/20240325/20240325-miso-seam-identified-issues-and-solutions-.ashx>.

114 See PJM and MISO Interregional Capability Study (ICTS) FAQ <https://www.pjm.com/-/media/DotCom/planning/interregional-planning/pjm-and-miso-interregional-transfer-capability-study-faq.pdf>.

115 See "PJM/MISO Interregional Transfer Capability Study," presented at the March 7, 2025 meeting of the PJM-MISO Interregional Planning Stakeholder Advisory Committee <https://www.pjm.com/-/media/DotCom/committees-groups/stakeholder-meetings/ipsac/2025/20250307/20250307-miso-pjm-ipsac-interregional-transfer-capability-study-itcs-to-pjm---working-draft.pdf>.

116 See PJM/MISO Interregional Transfer Capability Study (June 25, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/stakeholder-meetings/ipsac/2025/20250625/20250625-item-02---interregional-transfer-capability-study-update.pdf>.

117 See PJM/MISO Interregional Transfer Capability Study (June 25, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/stakeholder-meetings/ipsac/2025/20250625/20250625-item-02---interregional-transfer-capability-study-update.pdf>.

for the identified MISO and MISO intertie constraints that closed in May of 2025. MISO received 34 unique proposals from eight entities. Based on these proposals MISO developed 54 potential solution ideas for further evaluation by PJM and MISO. PJM and MISO have stated that they do not have a defined project type (and related cost allocation) to address all of the issues/benefits for the solutions identified in the ITCS process. PJM is reviewing the MISO potential solutions to see if any of the proposals are captured in the PJM RTEP reliability, RTEP Market Efficiency and/or the M-3 (Supplemental) process. In the case of any overlaps between RTEP and ITCS, PJM will consider the ITCS needs in RTEP solutions. PJM and MISO are planning for an update in the first quarter of 2026.

Multi Driver Process

On September 12, 2014, PJM filed revisions to the tariff to include provisions allowing PJM to include multi driver projects in its regional transmission expansion plan.[118] When a transmission project addresses a combination of reliability, market efficiency and/or public policy objectives, it is termed a multi driver project. PJM may choose a solution using either the proportional multi driver method or the incremental multi driver method. The proportional method combines separate solutions that address reliability, economics and/or public policy into a single transmission enhancement or expansion project. The incremental method expands a proposed single driver solution to include one or more additional component(s) to address a combination of reliability, economic and/or public policy drivers.[119] On February 20, 2015, the Commission approved the tariff revisions with an effective date of November 12, 2014.[120]

On June 7, 2022, PJM opened its first multi driver proposal window. The window seeks to address reliability and market efficiency needs on three identified facilities. PJM accepted proposed solutions until August 8, 2022. PJM received 14 proposals from three entities. After conducting a cost review, a reliability analysis and a market efficiency analysis on the 14 proposals and a combination of the proposals, PJM proposed a combination of two proposals made by two companies (Project 644 + 908) as its preferred solution. The preferred solution has an estimated capital cost of $82.30 million with a PJM determined expected benefit/cost ratio of 1.99.[121] PJM shared its recommendation with MISO for their evaluation. MISO did not indicate any concern with the proposed solution. On February 7, 2023, the PJM Board approved the recommended solution (Project 644 + 908).

The benefit/cost analysis used in the multi driver review is the same flawed benefit/cost analysis that PJM uses for evaluating Market Efficiency projects. PJM's assumed benefit of the combined project was calculated as the sum of the present value of positive (energy cost reductions to some loads) effects of $169.8 million. The sum of the present value of negative effects (energy cost increases to other loads), which was ignored in the PJM calculation of benefits, was $149.1 million. The total benefit of the proposed multi driver project is therefore only $20.7 million, not the $169.8 asserted by PJM, even ignoring the use of changes in congestion rather than changes in production costs. Using the total positive and negative effects to compare to the net present value of costs in the PJM's analysis, the benefit/cost ratio is 0.24, not 1.99. All $149.1 million of the increases in energy costs (negative benefits) would be paid by load in the ComEd Zone. Based on the requirement of benefit/cost ratio of 1.25, the energy efficiency portion of the multi driver project should have been rejected.

State Agreement Approach (SAA)

PJM's State Agreement Approach (SAA) is a provision in PJM's Operating Agreement that allows states to propose transmission projects for inclusion in PJM's Regional Transmission Expansion Plan if the state agrees to assume the full cost of the proposed transmission projects. The purpose of the SAA is to allow states to pursue their public policy goals without imposing costs on other states. The SAA can also be used by a group of states that agree to a transmission project as part of a collaborative goal. Under the SAA, a state can elect to select the entity to complete the project or the states can request that PJM open a competitive window to seek transmission solutions from developers that address the required upgrades. SAA projects are classified as public policy baseline projects or as a supplemental project developed by the selected PJM Transmission Owner. The state decides whether to pursue a project that comes out of the SAA process.

118 See PJM. Docket No. ER14-2864 (September 12, 2014).
119 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 58 (December 17, 2025).
120 150 FERC ¶ 61,117 (February 20, 2015).
121 See "2022 RTEP Multi-Driver Proposal Window No. 1," presented at the December 6, 2022 meeting of the Transmission Expansion Advisory Committee <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221206/item-07---multi-driver-proposal-window-update.ashx>.

Five states (Delaware, Maryland, North Carolina, Virginia and New Jersey) made a joint request to PJM to conduct a two phase study (The Offshore Wind Transmission Study) to determine reinforcements to the onshore grid to reliably deliver 6,416 to 17,016 of offshore wind plus additional RPS target requirements.[122] The phase one study, published on October 19, 2021, examined, at a high level, enhancements to the existing infrastructure needed to reliably integrate the proposed offshore wind generation, but did not include any estimates of the costs of the transmission infrastructure needed. The phase 1 study did not consider any greenfield transmission solutions, instead using existing facilities as potential points on injection (POI) and existing transmission paths as locations for upgrades. The study considered six scenarios.

Scenario 1 focused on a short term window that assumed a wind injection total of 6,416 MW and RPS targets through 2027 with a projected cost of $627 million. Scenario 1 included generator deactivations that were announced as of October 1, 2020, and were included in PJM's RTEP base case that formed the basis of the study. The other scenarios (Scenario 2 through Scenario 6) were longer term studies that looked out through 2035. Scenario 2, with a projected cost of $2,461.4 million, assumed 14,416 of offshore wind capacity and the same generator deactivations assumed in Scenario 1. Scenarios 2 through 6 assumed 1,739 MW of additional deactivated generation in addition to what was modeled in Scenario 1 and 2. Scenario 3 was abandoned due to legislation being withdrawn that had required the retirement of specific units. Scenario 4 assumed an increase (relative to Scenario 1) of 2,600 MW additional offshore wind connecting to Virginia POI resulting in projected costs of $3,213.1 million in needed upgrades. Scenario 5 assumed a different POI for Scenario 1 New Jersey offshore wind and cost $2,591.8 million in expected upgrade costs. Scenario 6 removed 2,000 MW of New Jersey offshore wind from Scenario 2 resulting in $2,164.3 million in projected upgrade costs.

The states decided to not pursue a joint Phase 2 study.

122 See Offshore Wind Transmission Study: Phase 1 Results, October 19, 2021 <https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.pdf>.

New Jersey State Agreement Approach (SAA) for Offshore Wind

In 2021, the New Jersey Board of Public Utilities (NJ BPU) initiated a proposal window under the SAA to meet New Jersey's goal of interconnecting up to 7,500 MW of offshore wind.[123] PJM received 80 proposals covering solutions that addressed onshore and offshore reliability criteria and transmission connections. The NJ BPU selected a proposal to interconnect 3,742 MW of offshore wind to central New Jersey at a total estimated cost for the project of $1.1 billion, with construction expected to start in 2027 and finish in 2029, with in service dates from December 2027 through June 2030. The costs for the NJ BPU offshore wind project would be recovered from customers in the state of New Jersey. On December 6, 2022, the PJM Board approved the BPU's proposal.

On October 31, 2023, Danish wind power developer Ørsted announced that it was canceling two major offshore wind projects, Ocean Wind 1 (1,100 MW) and Ocean Wind 2 (1,148 MW), that were planned off the coast of New Jersey. Prior this announcement, on September 22, 2023, Public Service Electric and Gas Company filed an application for an abandoned plant incentive to recover costs associated with the canceled wind projects.[124] The filing seeks "authorization for the ability to recover 100 percent of prudently incurred costs for certain transmission upgrades that PSE&G will construct in the event that the [offshore wind] transmission upgrades are abandoned or cancelled (in whole or in part) for reasons that are outside of PSE&G's control." Ørsted is taking a $2.9 billion impairment attributed to Ocean Wind 1.[125]

On December 31, 2025, only two New Jersey offshore wind projects remained, both in the serial queue and both suspended.

Maryland State Agreement Approach (SAA) for Offshore Wind

On December 5, 2024, the Maryland Public Service Commission (MD PSC) requested that PJM conduct analysis of Maryland's 8,500 MW off shore wind target, assuming three different POI scenarios, in response to the Maryland POWER Act of 2023. PJM provided the

123 See PJM Operating Agreement, Schedule 6, Section 1.5.9
124 See *Public Service Electric and Gas Company*, Docket No. ER23-2916 (September 22, 2023).
125 Ørsted, Ørsted ceases development of its US offshore wind projects Ocean Wind 1 and 2, takes final investment decision on Revolution Wind, and recognises DKK 28.4 billion impairments (October 31, 2023) <https://orsted.com/en/company-announcement-list/2023/10/oersted-ceases-development-of-its-us-offshore-wind-73751>.

requested study on March 21, 2025.[126] On June 23, 2025, the Maryland Public Service Commission requested that PJM issue a competitive solicitation for proposals under the SAA process for onshore injection of 2,000 MW offshore wind at Indian River by 2028 (DP&L), 1,500 MW of offshore wind at Cool Spring by 2030 (DP&L), 1,500 MW of offshore wind at Piney Grove by 2030 (DP&L), 1,500 MW of offshore wind at Nelson by 2030 (DP&L) and 2,000 MW of offshore wind at Calvert Cliff by 2031 (PEPCO).[127] PJM is currently working with the MD PSC to draft a SAA study agreement, which must be filed and approved by the Federal Energy Regulatory Commission (FERC). The goal is to have PJM open a competitive window in 2026 for the proposed requirements.

On December 31, 2025, only two Maryland offshore wind projects remained, both in the serial queue and both suspended.

Virginia's Coastal Virginia Offshore Wind (CVOW)

The Coastal Virginia Offshore Wind (CVOW) project is owned and operated by Dominion Energy. The project consists of 176 wind turbine generators, three offshore substations and nine buried submarine cables that will connect the wind turbines to the State Military Reservation in Virginia Beach, Virginia. With the exception of the near shore portion of the submarine cable length (within 3 miles of shore), the offshore project components will be located in federal waters. The CVOW project, designed to provide 2,600 MW of offshore wind, was scheduled for completion in 2026.

On January 20, 2025, the Trump Administration issued an executive order that temporarily prevented "consideration of any area in the OCS for any new or renewed wind energy leasing for the purposes of generation of electricity or any other such use derived from the use of wind."[128] The order stated that "[n]othing in this withdrawal affects rights under existing leases in the withdrawn areas." The order called for the Secretary of the Interior to conduct a comprehensive review of the ecological, economic, and environmental necessity of terminating or amending any existing wind energy leases. On December 8, 2025, a federal judge vacated the executive order.

On December 22, 2025, the US Interior Department, Bureau of Energy Management, issued a 90 day suspension of five offshore wind leases, including the lease associated with the CVOW project, due to national security concerns. During the suspension, the Interior Department has stated that it will coordinate with project developers to determine whether the national security threats posed by this project can be adequately mitigated. Dominion filed a law suit on December 23, 2025, asking the court to reject the pause.[129] As of December 31, 2025, work on the CVOW was on pause.[130]

On December 31, 2025, only three Dominion offshore wind projects remained, all in the cycle queue and all active.

Long Term Regional Transmission Planning

On May 13, 2024, the Commission issued Order No. 1920 which requires public utility transmission providers to engage in long-term regional transmission planning over a 20-year planning horizon, develop long-term scenarios to identify long-term transmission needs and enable the identification and evaluation of transmission facilities to meet those transmission needs. Order No. 1920 also requires transmission providers to determine a cost allocation method for long-term regional transmission facilities, make other reforms to enhance transparency in local transmission planning, to correctly size transmission projects and include interregional transmission coordination to support the development of cost-effective projects.[131]

On November 21, 2024, the Commission issued Order No. 1920-A.[132] Order No. 1920-A significantly expanded the role of States in the long-term regional transmission planning. Order No. 1920-A requires states' input into regional transmission planning and cost allocation processes, both in the transmission providers' development of Order No. 1920 compliance filings and the ongoing implementation of these reforms in the future. Order No. 1920-A also increases

126 See Maryland Offshore Wind Information Study Results, March 21, 2025 (https://webpscxb.psc.state.md.us/DMS/case/9800)
127 See Maryland PSC Request Letter, June 23, 2025 (https://webpscxb.psc.state.md.us/DMS/case/9800).
128 See January 20, 2025 Executive Order, Temporary Withdrawal of All Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects (https://www.whitehouse.gov/presidential-actions/2025/01/temporary-withdrawal-of-all-areas-on-the-outer-continental-shelf-from-offshore-wind-leasing-and-review-of-the-federal-governments-leasing-and-permitting-practices-for-wind-projects/).
129 Case No. 2:25-cv-00830-JKW-LRL (USDC E.D. Va.).
130 See Monthly Mariner's Update Costal Virginia Offshore Wind (CVOW), January 1, 2026 (https://coastalvawind.com/resources/docs/20260101_january_mariner_update.pdf)
131 See *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation, Order No. 1920*, 187 FERC ¶ 61,068 (2022).
132 See *Order on rehearing and clarification, Order No. 1920-A*, 189 FERC ¶ 61,126 (2024).

the states' role in: (i) developing long term scenarios; (ii) requesting additional scenarios beyond the three Long-Term Scenarios required by Order No. 1920; (iii) developing the evaluation processes and criteria for selecting new transmission facilities in the long-term regional transmission; (iv) developing cost allocation approaches for selected transmission facilities; and (v) voluntary funding opportunities.

PJM requested that the Commission extend PJM's deadline to comply with Order No. 1920's compliance directives by six months, (to December 12, 2025), while leaving the implementation deadline of two years after the initial due date of the compliance filing (June 12, 2027) unchanged. The extension was requested to accommodate the States' broader role required by Order No. 1920-A in developing Order No. 1920-compliant Long-Term Regional Transmission Planning protocols.[133] On December 12, 2025, PJM submitted its compliance filing.[134]

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."[135] Attachment M-3 of the PJM OATT defines the process that Transmission Owners (TO) must follow in adding Supplemental Projects in their local plan.

The M-3 Process requires TOs to present the criteria, assumptions and models that they will use to plan and identify Supplemental Projects on a yearly basis. The criteria identified for Supplemental Projects are very broad and include: equipment material condition, performance and risk, operational flexibility and efficiency, infrastructure resilience, customer service or other, as well as asset management.

While the identification of the criteria violations and solutions are reviewed, and stakeholders have the opportunity to comment, the solution that is submitted in the Local Plan is the Transmission Owner's decision. PJM conducts a do no harm analysis to ensure the Supplemental Projects do not negatively affect the reliability of the system. Supplemental Projects are ultimately included in PJM's Regional Transmission Expansion Plan and are allocated 100 percent to the zone in which the transmission facilities are located. Supplemental Projects may displace projects that would have otherwise been implemented through the RTEP process.

Supplemental projects are currently exempt from the Order No. 1000 competitive process.[136] 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 12-6 shows the latest cost estimate of all baseline and supplemental projects by expected in service year. Baseline projects are RTEP projects needed for reliability. FERC Order No. 890 was issued on February 16, 2007, and implemented in PJM starting in 2008. Order No. 890 required Transmission Providers to participate in a coordinated, open and transparent planning process. Prior to the implementation of Order No. 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 12-6, Table 12-82 and Table 12-83 because PJM did not track or report such projects. There has been a significant increase in supplemental projects coincident with the implementation of Order No. 890 starting in 2008 and the competitive planning process introduced by FERC Order No. 1000 starting in 2011.

PJM's data collection, management and retention related to transmission spending of all types is inadequate and needs a significant upgrade. The failure to collect data on estimated and final project costs makes it impossible to track transmission project costs for all project types. Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data.

133 See PJM Interconnection, L.L.C., Docket No. RM21-17-000 (December 20, 2024).
134 See PJM Interconnection, L.L.C., Docket No. ER26-750-000 (December 12, 2025).
135 See PJM. Planning. "Transmission Construction Status," (Accessed on December 31, 2025) <https://www.pjm.com/planning/project-construction>.
136 FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).

Figure 12-6 Cost estimate of baseline and supplemental projects by expected in service year: January 1, 1998 through December 31, 2025

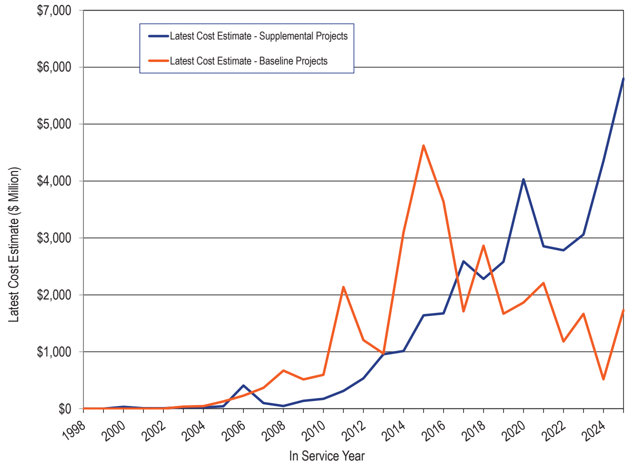


Table 12-82 shows the number of supplemental projects by expected in service year for each transmission zone. The average number of supplemental projects in each expected in service year increased by 1,105.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 241 for years 2008 through 2025 (post Order No. 890). As of December 31, 2025, there were 2,299 supplemental projects with expected in service dates between January 1, 2025 and December 31, 2036.

Table 12-82 Number of supplemental projects by expected in service year and zone: 1998 through 2050

Year	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	NEET	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
1998	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	3
1999	0	0	0	0	0	0	0	0	0	0	0	2	0	0	1	0	0	0	0	0	0	0	0	3
2000	0	0	0	0	0	0	0	0	0	0	0	11	0	0	0	0	0	0	0	0	0	0	0	11
2001	0	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	0	0	0	14
2002	0	0	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	0	0	0	0	0	10
2003	3	0	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	2	0	0	0	0	15
2004	5	0	0	10	0	0	9	0	0	0	0	12	0	2	0	0	0	0	0	0	0	2	0	40
2005	4	2	0	8	0	0	4	0	0	0	1	14	0	1	0	0	0	1	2	0	0	2	0	39
2006	4	2	0	5	0	0	6	0	0	0	0	9	0	1	0	0	0	0	1	0	2	1	0	31
2007	1	1	0	5	0	4	5	0	0	4	0	6	0	0	0	0	0	0	2	0	1	6	0	35
2008	3	0	0	15	0	1	6	0	0	1	7	3	0	0	1	0	0	0	0	0	3	1	0	41
2009	3	1	0	6	0	1	8	0	0	3	3	5	0	0	0	0	0	5	1	0	1	2	0	39
2010	0	6	0	7	0	3	4	0	0	6	3	0	0	1	2	0	0	2	0	0	3	5	0	42
2011	0	8	0	8	0	0	2	0	0	5	2	0	0	1	0	0	0	4	0	0	7	4	0	41
2012	0	5	0	6	4	1	2	0	7	3	16	1	0	2	0	0	0	1	0	0	6	11	0	65
2013	5	21	0	4	5	0	11	0	6	4	13	1	0	1	1	0	0	1	0	1	14	19	0	107
2014	2	31	0	2	8	2	14	0	5	6	18	3	3	2	0	0	0	1	2	0	10	15	0	124
2015	4	15	0	2	9	1	37	0	8	4	17	5	3	2	0	0	0	1	0	4	7	22	0	141
2016	6	17	0	4	17	0	26	0	6	2	13	4	2	0	1	0	0	3	2	3	11	29	0	146
2017	8	107	0	3	26	1	23	0	3	8	31	11	5	0	3	0	0	0	3	1	22	43	0	298
2018	10	144	0	3	13	1	20	0	14	3	22	6	4	0	0	0	0	2	0	1	20	25	0	288
2019	3	163	0	4	30	5	14	2	16	1	33	8	5	3	14	0	0	1	15	0	15	27	0	359
2020	5	132	0	4	35	6	12	7	13	1	30	2	6	9	17	0	0	3	33	1	17	23	0	356
2021	4	155	0	6	30	8	4	5	13	2	22	0	8	17	22	0	0	22	24	0	19	23	0	384
2022	1	153	0	10	31	5	10	6	9	1	28	2	6	14	34	0	0	5	29	0	18	17	0	379
2023	5	186	0	17	19	10	6	4	9	1	35	4	6	5	20	2	0	5	12	5	15	20	0	386
2024	7	241	1	27	28	11	8	18	3	0	31	4	10	16	26	0	0	9	22	8	16	16	0	502
2025	2	315	1	14	32	10	7	14	13	7	41	0	6	25	44	0	0	4	56	8	20	16	0	635
2026	1	190	4	26	28	8	17	18	11	2	54	2	9	26	29	0	0	1	31	1	28	12	0	498
2027	4	148	7	32	26	0	12	16	6	3	39	2	6	20	19	0	5	3	17	3	49	18	0	435
2028	4	145	0	17	17	4	6	7	5	0	38	3	3	15	6	0	0	5	10	4	26	12	0	327
2029	8	85	0	27	6	0	0	4	4	0	16	2	4	4	2	0	0	2	1	1	10	14	0	190
2030	4	71	1	2	3	0	0	3	0	0	14	0	2	3	0	0	0	0	0	4	8	0	0	115
2031	1	45	0	1	3	3	0	0	2	0	0	1	0	1	0	0	0	0	0	0	0	0	0	57
2032	2	7	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12
2033	0	0	0	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	16	0	0	18
2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	0	4	0	0	10
2035	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2036	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
2037	0	0	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	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	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	0	0
2041	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2042	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2043	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2044	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2045	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2046	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2047	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2048	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2049	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2050	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	2
Total	109	2,398	14	279	370	85	273	104	153	68	529	160	88	171	242	2	5	81	271	45	368	385	0	6,200

Table 12-83 shows the latest cost estimate of supplemental projects by expected in service year for each transmission zone. The average cost of supplemental projects in each expected in service year increased by 3,001.0 percent, from $64.5 million for years 1998 through 2007 (pre Order No. 890) to $2.0 billion for years 2008 through 2025 (post Order No. 890). As of December 31, 2025, the 2,299 supplemental projects with expected in service dates between January 1, 2025 and December 31, 2036, have a total cost estimate of $32.6 billion.

Table 12-83 Latest cost estimate by expected in service year and zone ($ millions): 1998 through 2050

Year	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	NEET	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
1998	$0.00	$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	$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	$0.00	$0.77	$0.00	$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	$0.00	$32.94	$0.00	$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	$0.00	$6.79	$0.00	$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	$0.00	$6.99	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.99
2003	$7.42	$0.00	$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	$0.00	$9.60	$0.00	$0.00	$0.00	$0.00	$25.79
2004	$4.45	$0.00	$0.00	$10.00	$0.00	$0.00	$0.82	$0.00	$0.00	$0.00	$0.00	$7.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22.60
2005	$4.06	$14.66	$0.00	$10.12	$0.00	$0.00	$2.57	$0.00	$0.00	$0.00	$0.02	$10.98	$0.00	$0.00	$0.00	$0.00	$0.00	$0.50	$0.00	$0.00	$0.00	$0.00	$0.00	$42.91
2006	$4.03	$309.70	$0.00	$0.93	$0.00	$0.00	$48.93	$0.00	$0.00	$0.00	$0.00	$11.62	$0.00	$6.00	$0.00	$0.00	$0.00	$0.00	$1.50	$0.00	$4.63	$18.80	$0.00	$406.14
2007	$0.56	$2.06	$0.00	$9.85	$0.00	$37.61	$4.64	$0.00	$0.00	$31.75	$0.00	$9.71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.34	$2.28	$0.00	$98.80
2008	$2.36	$0.00	$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	$0.00	$1.59	$0.00	$0.00	$47.32
2009	$0.77	$0.90	$0.00	$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	$0.00	$48.10	$2.73	$0.00	$0.16	$17.60	$0.00	$137.66
2010	$0.00	$34.36	$0.00	$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	$0.00	$31.80	$0.00	$0.00	$1.86	$17.72	$0.00	$172.19
2011	$0.00	$37.60	$0.00	$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	$0.00	$113.30	$0.00	$0.00	$11.87	$34.60	$0.00	$311.22
2012	$0.00	$46.00	$0.00	$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	$0.00	$12.60	$0.00	$0.00	$19.66	$223.01	$0.00	$532.54
2013	$3.15	$134.93	$0.00	$1.10	$33.68	$0.00	$59.25	$0.00	$9.93	$79.10	$25.03	$0.99	$0.00	$0.05	$4.10	$0.00	$0.00	$22.50	$0.00	$2.40	$76.70	$503.72	$0.00	$956.63
2014	$8.03	$387.00	$0.00	$5.97	$58.70	$21.20	$60.37	$0.00	$2.43	$14.90	$88.61	$5.96	$0.72	$5.60	$0.00	$0.00	$0.00	$13.30	$1.30	$0.00	$33.47	$305.30	$0.00	$1,012.86
2015	$3.73	$237.45	$0.00	$3.80	$21.90	$2.00	$376.00	$0.00	$14.12	$4.53	$113.53	$13.06	$1.22	$0.30	$0.00	$0.00	$0.00	$33.80	$0.00	$42.50	$50.17	$721.91	$0.00	$1,640.02
2016	$74.54	$84.13	$0.00	$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	$0.00	$86.40	$0.40	$7.80	$58.76	$742.48	$0.00	$1,675.74
2017	$66.28	$648.74	$0.00	$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	$0.00	$8.30	$12.00	$264.34	$988.92	$0.00	$2,589.07
2018	$66.55	$818.03	$0.00	$14.60	$42.12	$4.08	$80.94	$0.00	$69.80	$3.13	$162.94	$68.94	$10.87	$0.00	$0.00	$0.00	$0.00	$47.60	$0.00	$156.00	$197.34	$537.85	$0.00	$2,280.79
2019	$64.30	$1,114.64	$0.00	$11.97	$190.40	$76.55	$90.19	$0.30	$90.69	$0.30	$90.14	$33.55	$23.67	$0.90	$62.30	$0.00	$0.00	$2.00	$75.80	$0.00	$298.00	$356.41	$0.00	$2,582.11
2020	$59.58	$920.44	$0.00	$0.30	$115.41	$62.58	$78.09	$14.36	$72.06	$6.40	$258.72	$39.50	$25.61	$2.30	$23.10	$0.00	$0.00	$2.40	$72.70	$102.70	$215.29	$1,959.38	$0.00	$4,030.92
2021	$86.54	$1,192.02	$0.00	$9.50	$184.21	$32.52	$140.90	$17.79	$117.39	$18.90	$98.40	$0.00	$25.67	$47.84	$85.89	$0.00	$0.00	$73.40	$63.48	$0.00	$197.67	$460.84	$0.00	$2,852.96
2022	$81.40	$805.01	$0.00	$19.32	$205.52	$190.13	$147.60	$21.46	$64.32	$45.00	$194.60	$9.38	$22.12	$34.84	$127.04	$0.00	$0.00	$72.80	$59.79	$0.00	$231.92	$450.83	$0.00	$2,783.08
2023	$59.10	$851.33	$0.00	$49.09	$160.41	$18.35	$48.34	$25.60	$112.27	$0.00	$333.30	$87.57	$29.77	$3.41	$130.50	$68.77	$0.00	$24.40	$20.07	$218.84	$191.73	$628.26	$0.00	$3,061.11
2024	$87.60	$1,655.60	$20.00	$69.91	$199.70	$23.84	$219.60	$202.60	$31.73	$0.00	$498.66	$95.30	$61.42	$87.73	$103.80	$0.00	$0.00	$173.57	$63.18	$5.54	$235.95	$517.54	$0.00	$4,353.27
2025	$44.63	$2,148.38	$18.00	$150.45	$513.01	$141.20	$156.75	$66.55	$110.72	$50.55	$481.92	$0.00	$68.94	$129.79	$187.91	$0.00	$0.00	$13.39	$178.56	$595.10	$353.45	$390.00	$0.00	$5,799.30
2026	$9.45	$1,880.43	$25.54	$228.31	$345.65	$405.92	$446.30	$129.71	$125.23	$0.00	$1,422.90	$63.40	$10.23	$122.16	$140.66	$0.00	$0.00	$25.90	$56.10	$0.50	$490.45	$283.45	$0.00	$6,212.29
2027	$91.70	$1,349.00	$78.50	$219.38	$539.24	$0.00	$717.25	$129.51	$60.15	$168.50	$1,087.70	$14.10	$93.07	$188.13	$151.74	$0.00	$4.40	$61.40	$137.10	$2.04	$1,028.23	$493.90	$0.00	$6,615.04
2028	$100.19	$1,113.27	$0.00	$120.14	$360.45	$491.55	$564.90	$33.80	$43.25	$0.00	$964.95	$73.78	$31.13	$82.74	$142.70	$0.00	$0.00	$54.40	$251.70	$3.24	$523.56	$812.18	$0.00	$5,767.93
2029	$162.94	$555.99	$0.00	$213.24	$140.52	$0.00	$0.00	$46.20	$84.43	$0.00	$1,006.42	$37.50	$69.76	$27.21	$26.40	$0.00	$0.00	$118.00	$138.00	$0.50	$311.90	$745.15	$0.00	$3,684.16
2030	$220.20	$494.39	$29.00	$38.80	$49.50	$0.00	$0.00	$74.30	$0.00	$0.00	$405.55	$0.00	$21.20	$16.92	$0.00	$0.00	$0.00	$0.00	$0.00	$22.00	$58.75	$0.00	$0.00	$1,430.61
2031	$31.50	$941.23	$0.00	$18.80	$453.70	$276.00	$0.00	$0.00	$11.00	$0.00	$0.00	$42.50	$0.00	$8.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,782.73
2032	$84.00	$285.05	$0.00	$5.38	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$374.43
2033	$0.00	$0.00	$0.00	$1.90	$0.00	$0.00	$0.00	$0.00	$0.00	$30.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$242.17	$0.00	$0.00	$274.47
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	$443.00	$0.00	$89.40	$0.00	$0.00	$532.40
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	$0.00	$0.00
2036	$0.00	$166.60	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$166.60
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	$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	$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	$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	$0.00	$0.00
2041	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2042	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2043	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2044	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2045	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2046	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2047	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2048	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2049	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2050	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.50
Total	$1,429.06	$18,228.94	$171.04	$1,290.66	$3,961.62	$1,810.17	$3,741.26	$762.18	$1,125.02	$573.40	$7,668.34	$812.60	$497.86	$771.72	$1,207.79	$68.77	$4.40	$1,031.56	$1,583.31	$1,171.16	$5,189.36	$11,212.13	$0.00	$64,312.35

On September 28, 2023, the Office of Ohio Consumers' Counsel filed a complaint regarding the impact of the volume and costs of supplemental projects on consumers. The complaint requests that the Commission develop a mechanism, to be included in the PJM Tariff and Operating Agreement, whereby "FERC would review the need, prudence and cost-effectiveness of local transmission projects in Ohio." The complaint also requests the Commission to appoint an Independent Transmission Monitor (ITM) to assist "in reviewing the planning, need, prudence and cost-effectiveness of local transmission projects for consumers in Ohio", and to "consider precluding the Ohio Transmission Utilities from using formula rates for establishing transmission rates."[137] The Office of Ohio Consumers' Counsel's complaint is pending.

On December 19, 2024, a group of consumer interests filed against multiple transmission owners and RTOs/ISOs.[138] The complaint alleges that provisions in the tariffs of the transmission owning utilities and the RTOs/ISOs inappropriately authorize individual transmission owners to plan facilities rated at 100 kilovolts kV and above without regard to efficiency or cost-effectiveness. The complaint does not challenge the rates for any specific locally planned projects,

137 See Office of the Ohio Consumers' Counsel v. PJM, et al., Docket No. EL23-105 (September 28, 2023).
138 See Industrial Energy Consumers of America v. PJM, et al., Docket No. EL25-44-000 (December 19, 2024).

but, rather, alleges that the cumulative effect of tariff provisions allowing local planning of transmission projects rated at 100 kV and above results in unjust and unreasonable transmission rates.[139] The complaint requests issuance of an order that, for transmission facilities rated at 100 kV and above, requires: (i) removal of planning from transmission owner tariffs (and RTO tariffs that confirm such transmission owner planning); (ii) amendment of regional planning tariffs to require that all planning be done at the regional or interregional level (specifying facilities reaching the end of operational life); and (iii) amendment of regional planning tariffs be to require that the regional planning within the existing Order No. 1000 regions be conducted by independent transmission system planners.[140] The complaint recommends that independent transmission planners be structured similar to independent market monitors or be included in an expanded market monitoring function.[141] The consumer interests' planning complaint is pending.

The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated.

End of Life Transmission Projects

An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. Under the current process, end of life transmission projects are not subject to the RTEP open window process and have become a form of supplemental project that is exempt from competition under the existing rules.[142]

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 be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to require 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.** If the violation needs to be resolved within three years or less, all such projects are excluded from competition. The local Transmission Owner is the Designated Entity.[143]

  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.[144] Some supplemental projects are in this category. In a decision issued August 19, 2022, the U.S. Court of Appeals for the D.C Circuit found that FERC reasonably approved MISO's Immediate Need Reliability Exception.[145] The Court rejected arguments challenging the MISO rule because (i) the definition of projects eligible for the exception was insufficiently limited and (ii) the rule allows for designating the incumbent developer before posting of the basis for the exception.[146] The decision was largely based on deference to FERC expertise.[147]
- **Below 200kV.** All projects at voltages less than 200kV are excluded from competition. The local Transmission Owner is the Designated Entity.[148] Some supplemental projects are in this category.
- **Substation Equipment.** If the limiting element(s) is substation equipment, such projects are excluded from competition. The local Transmission Owner is the Designated Entity.[149] Some supplemental projects are in this category.

While the PJM Operating Agreement defines 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 require competition to provide financing for transmission projects. This competition could reduce the cost of

139 *Id.* at 11.
140 *Id.* at 42–43.
141 *Id.*, Attachment C (Declaration of Michael A. Giberson) at 36:11–37:8.
142 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), *affirmed*, American Municipal Power, Inc., et al. v. FERC, Case No. 20-1449 (D.C. Cir. November 17, 2023), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).
143 See OA Schedule 6 § 1.5.8(m).
144 169 FERC ¶ 61,054 (2019).
145 LSP Transmission Holdings II, LLC v. FERC, 45 F.4th 979.
146 *Id.* at 999.
147 *Id.*
148 See OA Schedule 6 § 1.5.8(n).
149 See OA Schedule 6 § 1.5.8(p).

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.

Dominion Data Center Alley Immediate Need and Long Term Solution

Dominion presented 44 supplemental project requests to serve new data center load through the summer of 2025. PJM identified the need for additional baseline reinforcements to support the load growth. Rather than a competitive process, PJM decided to designate the upgrades as immediate need and allowed Dominion to construct these lines.[150] [151]

The 2022 RTEP Window 3 addressed long term reliability needs as well as the additional baseline reinforcements for Data Center Alley. The proposal window was open from February 24, 2023, to May 31, 2023, and received 72 submissions from 10 entities. The cost estimate for the total scope of work was $5.1 billion, $1.4 billion of which was for the necessary baseline upgrades specific to the Data Center Alley reinforcements.[152] The proposed Data Center Alley solution includes 500kV and 230kV lines extensions, the reconductoring of multiple 230kV lines and substation work.[153]

On December 8, 2023, the Maryland Office of People's Counsel (MDOPC) submitted a letter to the PJM Board.[154] The letter requested that the PJM Board defer the December 11, 2023, vote on the 2022 RTEP Window 3 proposal. The MDOPC letter cited concerns regarding the scale, scope and cost of the proposal. Additionally, the MDOPC expressed concerns that "the current failure to unpack the relative contribution of each of the "drivers" of the need for the W3 projects makes it impossible for the public to understand how cost causation principles apply to the projects." On December 11, 2023, the PJM Board approved the recommended solution. PJM filed the RTEP on January 10, 2024, and the Commission accepted it by order issued April 8, 2024.[155]

Comparative Cost Framework

The MMU recommended that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. 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 cost framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. On March 20, 2020, the Commission approved PJM's filing to amend the PJM Operating Agreement to incorporate this requirement.[156]

The 2020 RTEP Window 1 was the first open window that received cost capping proposals to be evaluated under the comparative cost framework. PJM has not provided the requested data to the MMU to allow for an analysis of their financial review process. Without this data and analysis, the MMU cannot verify that the analysis performed under the comparative cost framework was sufficient or adequately followed the process defined in the PJM manual.[157] The existing proposal templates do not provide enough information to adequately perform a financial analysis. The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life.

Storage As A Transmission Asset (SATA)

The PJM Planning Committee considered whether storage devices should be included in the RTEP process as transmission assets.[158] On February 24, 2021, the Markets and Reliability Committee (MRC) voted to defer endorsement of governing document language

150 See "Dominion Northern Virginia Area Violations," presented at the July 12, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220712/item-08---dominion-northern-virginia-area-violations---need-statement.ashx>.
151 See "Dominion Northern Virginia Area Immediate Need," presented at the July 12, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220712/item-08---dominion-northern-virginia---immediate-need.ashx>.
152 See "*Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board*," December 2023. <https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-pjm-teac-board-whitepaper-december-2023.ashx>.
153 See "*Reliability Analysis Report: 2022 RTEP Window 3*," December 8, 2023. <https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-2022-rtep-window-3-reliability-analysis-report.ashx>.
154 See "MD Office of People's Counsel Letter regarding 2022 RTEP Window 3 Procurement," <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20231208-pjm-board-letter-2023-12-08-md-opc-final.ashx>.
155 See 187 FERC ¶ 61,012. Maryland Office of the People's Counsel filed a protest, which the Commission determined was outside of the scope of the RTEP filing.
156 See 170 FERC ¶ 61,243 (2020).
157 See "PJM Manual 14F: Competitive Planning Process," Rev. 10 (October 30, 2024).
158 See PJM. "*Storage As A Transmission Asset: Problem / Opportunity Statement*," <https://pjm.com/-/media/committees-groups/committees/pc/2020/20200605-special/20200605-item-02a-storage-as-a-transmission-asset-problem-statement-clean.ashx>.

associated with Storage as a Transmission Asset in reliability planning. The MRC chose to defer the language until a comprehensive proposal addressing all aspects of incorporation of storage resources into markets, operations and planning.

Transmission and generation have, and have always had, a symbiotic relationship in the provision of wholesale power. Transmission needs generation to function and generation needs transmission to function. Transmission can substitute for generation at the margin and generation can substitute for transmission at the margin. This relationship has always been a relatively unexamined area in the design of competitive wholesale power markets. For example, there is little if any explicit consideration of the impact of transmission planning on competitive generation investment in RTO/ISO market rules. Improvement is needed in these areas. Introducing confusion about what assets are classified as generation and what assets are classified as transmission frustrates potential reform and undermines the competitive markets.

On July 22, 2020, through the supplemental planning process, American Electric Power Service Corporation (AEP) filed, on behalf of Kentucky Power Company (Kentucky Power), a Petition for Declaratory Order seeking confirmation that its Middle Creek energy storage project is eligible for cost of service recovery through AEP's formula rates.[159] AEP's Middle Creek energy storage project was a proposed battery storage device that would discharge energy to serve retail load at the Middle Creek substation in the event of a transmission outage. On December 21, 2020, the Commission ruled that the Middle Creek energy storage project did not perform a transmission function, and was ineligible to recover its costs through formula rates.[160]

Storage devices like batteries that are defined to be part of PJM markets should not be treated as transmission assets. These devices should be treated as market assets. The MMU recommends that storage resources not be includable as transmission assets for any reason.

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.[161]

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 2025, the PJM Board approved a net change of $8.5 billion in transmission upgrades. As of December 31, 2025, the PJM Board had approved $58.5 billion in transmission system enhancements since 1999.

Qualifying Transmission Upgrades (QTU)

A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system, financed and built by market participants, 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 Base Residual Auction (BRA) or Incremental Auction (IA) 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, 2025, no QTUs have cleared a BRA or IA.

159 See *AEP*, Docket No. EL20-58 (July 22, 2020).
160 173 FERC ¶ 61,264 (2020).
161 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

Cost Allocation

Required transmission enhancements are categorized as: supplemental, network or baseline upgrades. The cost allocation of the transmission enhancements depends on the category of upgrades.

Supplemental Upgrade Cost Allocation

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."[162] Supplemental projects are exempt from competition. The costs of supplemental projects are allocated 100 percent to the zone in which the transmission facilities are located.[163]

Network Upgrade Cost Allocation

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.[164] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. The process assigns the upgrade costs to the project or projects that are causing the costs to be incurred. As part of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of interconnecting projects in the queue. The interconnection service agreement identifies the transmission modifications needed to maintain the reliability of the transmission system as a result of a new service request. These identified modifications are known as network upgrades. For required network upgrades under the new cluster based service request cycles, the costs of the network upgrades are assigned to individual projects that caused the costs to be incurred.[165]

162 See PJM. "Transmission Construction Status," (Accessed on December 31, 2025) <https://www.pjm.com/planning/m/project-construction>.
163 See OATT Schedule 12(a)(iii).
164 See OATT Parts IV & VI.
165 See "PJM Manual 14H: New Service Requests Cycle Process," Rev. 03 (September 25, 2025).

Baseline Upgrade Cost Allocation

The PJM RTEP process is designed to identify needed transmission system additions and improvements to continue to provide reliable service throughout the RTO. Typically, load growth creates conditions that may create violations of reliability criteria, which in turn require upgrades. The PJM RTEP identifies necessary upgrades to remain compliant with national and regional reliability standards. These modifications are baseline upgrades. Baseline upgrades can also include market efficiency projects.

The costs of regional baseline facilities are allocated 50 percent on a load-ratio share and 50 percent on a directionally weighted solution based DFAX method.[166]

The costs of the necessary lower voltage facilities required to support the regional baseline facilities with estimated costs greater than or equal to $5 million are assigned on a directionally weighted solution based DFAX method.

The costs of the necessary lower voltage facilities required to support the regional baseline facilities with estimated costs below $5 million are assigned to the zone where the upgrade is located.

In response to complaints against PJM RTEP Baseline Upgrade Filings in 2014 that included cost allocations for $1.5 billion in baseline transmission enhancements and expansions, on November 24, 2015, FERC issued an order directing investigation of "whether there is a definable category of reliability projects within PJM for which the solution-based DFAX cost allocation method may not be just and reasonable, such as projects addressing reliability violations that are not related to flow on the planned transmission facility, and whether an alternative just and reasonable *ex ante* cost allocation method could be established for any such category of projects."[167] FERC convened a technical conference on January 12, 2016, to address the complaints in multiple proceedings and to address these two core issues.[168]

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

166 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 58 (December 17, 2025) for a complete explanation of the directionally weighted solution based DFAX method.
167 153 FERC ¶ 61,245 at P 35 (2015).
168 See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).

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.

On February 20, 2020, the Commission issued an Order denying rehearing requests.[169] The Commission found that PJM's solution based dfax method for regional cost allocation, including the 0.01 distribution cutoff factor, is just and reasonable.

On appeal, the U.S. Court of Appeals for the D.C. Circuit in 2022 found that FERC had failed to explain its distinction between the projects eligible to use the dfax method and those not eligible.[170] The Court objected that without adequate explanation: "The Bergen project 'addresses a non-flow related reliability issue,' just like the non-flow-based stability issue in Artificial Island, but FERC had treated the two projects differently."[171] The Court also rejected the 0.01 distribution cutoff factor as "absurd."[172] The Court remanded issues concerning PJM's solution based dfax method to FERC, where the matter is now pending.[173]

It is clear that the allocation issues are difficult. Nonetheless, allocation methods affect the efficiency of the markets. Allocation methods also affect the degree to which transmission upgrades required to serve data center load are allocated to other customers. The MMU recommends a comprehensive review of the ways in which the solution based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives are thoroughly reviewed.

As an example, 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 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.

169 See 170 FERC ¶ 61,122 (2020).
170 See *Consolidated Edison v. FERC et al.*, 45 F.4th 265 (D.C. Cir. August 9, 2022).
171 *Id.* at 9.
172 See *id.*
173 See FERC Docket Nos. EL21-39-000, et al.

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. Line ratings directly affect 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 costs for the interconnection of 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. The fact that PJM rules continue to fail to ensure the return of 100 percent of congestion costs to the load that pays them means that higher congestion increases costs to load.

LMP may, at times, be set by transmission constraint 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 constraint penalty factors. The shadow price directly affects the LMP. Transmission constraint penalty factors were fully implemented in PJM pricing effective February 1, 2019.[174]

Transmission line ratings can result in short term, significant increases in prices as a result of the application of transmission constraint penalty factors. For example, violation of a transmission constraint, meaning that the flow exceeds the line limit, generally results in at least a $2,000 per MWh price. As the power flows approach their rated limits, PJM dispatchers often reduce the control percent on transmission limits applied in SCED by the setting the limit to an average of 95 percent of its actual limit.[175] Violation of these reduced control percent line ratings results in penalty factors setting prices in SCED.[176]

Holding aside the issues with operators reducing the control percent in SCED, the more important point is that the underlying line ratings have a significant impact on the cost of energy and capacity but have never been reviewed or standardized by ISOs/RTOs or by regulators. The line ratings issues will begin to be addressed beginning on July 12, 2025.[177]

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.[178]

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.[179] 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.[180]

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. New technologies that permit dynamic line ratings (DLR) should be implemented.

174 For more information, see the *2024 Annual State of the Market Report for PJM*: Volume 2, Section 3: Energy Market.

175 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>.

176 See the *2024 Annual State of the Market Report for PJM*: Volume 2, Section 3: Energy Market.

177 *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 at P 39 (2021) ("Order No. 881"), *order on reh'g*, Order No. 881-A, 179 FERC ¶ 61,125 (2022) ("Order No. 881-A").

178 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).

179 See "PJM Manual 03: Transmission Operations," Rev. 69 (November 20, 2025) § 2.1.1, at p 30.

180 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.

Line ratings determine the actual value of transmission in market operations. Yet the methods for defining line ratings remain opaque and vary significantly across transmission owners. Under defining line ratings results in over building transmission. Dynamic line ratings are essential to reflect the actual availability of transmission in real time as ambient conditions change. Ensuring that system operators have accurate information about line ratings, including a wide range of line ratings by duration of load, are essential to ensure that all market participants receive the maximum value from the investment in the transmission system.

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. In PJM, real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings.

The MMU recommends that all PJM transmission owners use the same methods to define line ratings and implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, 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 relevant.[181] 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.[182] All line rating changes and the detailed reasons for those changes should be public and fully transparent.

The Commission adopted rules that enhance the ability of PJM and the MMU to understand and monitor line ratings on the PJM grid. Order No. 881, issued December 16, 2021, requires that: transmission providers implement ambient adjusted ratings on transmission lines; RTOs/ISOs implement the systems and procedures necessary for hourly ratings updates; transmission providers use uniquely determined emergency ratings; transmission owners share transmission line ratings and transmission line rating methods with RTOs/ISOs and market monitors; transmission providers maintain a database of transmission line ratings and transmission line rating methods on OASIS or other password-protected website.[183] [184]

On rehearing, the Commission provided clarification of market monitors' ability to take action based on information received about transmission line ratings: "We expect that market monitors may use the transmission line rating information available to them in furtherance of their existing responsibilities, which are set forth in the Commission's regulations and the relevant tariffs of each RTO/ISO."[185]

Order No. 881 enhances transparency of information on line ratings and how they are determined. Requiring ambient and hourly adjustments constitutes substantive improvement. Continued reform consistent with the MMU's recommendations is needed in order to ensure consistent and accurate transmission line ratings in PJM.

By letter order issued November 22, 2023, the Commission accepted PJM's filing in compliance with Order Nos. 881 and 881-A, to be implemented no later than July 12, 2025.[186]

On February 28, 2025, PJM requested that the Commission extend PJM's deadline to comply with Order No. 881 compliance directives by nine months, (to no later than April 15, 2026).[187] The extension was requested to allow for required software development and testing. On March 31, 2025, the Commission approved the implementation extension request.[188] On

181 *See* "Transmission Owner Ratings Development and Reporting in PJM," presented at May 3, 2018 meeting of the Planning Committee.
182 *See* the *2024 Annual State of the Market Report for PJM*: Volume 2,Section 3: Energy Market.

183 *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 at P 39 (2021) ("Order No. 881"), *order on reh'g*, Order No. 881-A, 179 FERC ¶ 61,125 (2022) ("Order No. 881-A").
184 *See* 18 CFR § 35.28(c)(5)ii(g)(13).
185 Order No. 881-A at P 91.
186 See Docket No. ER22-2359-000. PJM must notify the Commission of the effective date no later than November 12, 2024.
187 See PJM, Docket No. ER22-2359-000. (February 28, 2025).
188 See 190 FERC ¶ 61,204 (March 31, 2025).

December 31, 2025, the Order 881 implementation date was March 4, 2026.

Order No. 881 did not require the use of dynamic line ratings ("DLR") based on an insufficient record.[189] On June 27, 2024, the Commission issued an Advanced Notice of Proposed Rulemaking in Docket RM24-6 on the implementation of dynamic line ratings.[190]

Dynamic Line Ratings (DLR) and Grid Enhancing Technology (GETs)

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 relevant real-time conditions include ambient air temperature, wind speeds, solar heating, transmission line tension, and transmission line sag. The widespread adoption of dynamic line ratings should be pursued. The adoption of dynamic line ratings does not require the exorbitant incentives proposed by some. Dynamic line rating technology (DLR) and other Grid Enhancing Technology (GET) should be subject to competition and the costs of implementation should be capped at the costs that would result from the current cost of service method applied to transmission owners. The proposal that providers of GET should receive a share of forecast benefits is not consistent with competition, would pay rates of return many multiples of market rates of return and suffers from the same intractable problem of defining speculative benefits for long periods.

As a first small step towards broader implementation of DLR by all transmission owners in PJM, PPL Electric Utilities, on its own initiative, implemented DLR for three 230 KV transmission lines in northeastern Pennsylvania on October 6, 2022, that have experienced congestion. (The two circuit Susquehanna-Harwood path and the Juniata-Cumberland line.) PPL provides streaming data from the DLR system to PJM operators.

PJM developed technical reference guides to aid in the understanding and consideration of grid enhancing technologies on the PJM system. The technical reference guides provide additional information on dynamic line ratings, advanced power flow controllers, topology control and optimization and advanced conductors.[191]

189 Order No. 881 at PP 25, 254.
190 See 187 FERC ¶ 61,201.
191 See PJM. About PJM "Grid Optimization Solutions," <https://www.pjm.com/about-pjm/advanced-technologies/grid-optimization-solutions>.

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.[192] 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.[193] The specific timeline is shown in Table 12-85.[194]

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 2024/2025 planning period and the first seven months of the 2025/2026 planning period, regardless of when they were initially submitted.[195] The outage data for the day-ahead market are for outages scheduled to occur from January 2015 through December 2025.

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.[196] Table 12-84 shows that 70.8 percent of requested outages were planned for less than or equal to five days and 11.6 percent of requested outages were planned for greater than 30 days in the first seven months of the 2025/2026 planning period. Table 12-84 also shows that 75.2 percent of the requested outages were planned for less than or equal to five days and 9.2 percent of requested outages were planned for greater than 30 days in the 2024/2025 planning period.

192 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. 69 (Nov. 20, 2025).
193 See PJM, "Manual 3: Transmission Operations," Rev. 69 (Nov. 20, 2025).
194 See PJM, "Manual 3: Transmission Operations," Rev. 69 (Nov. 20, 2025).
195 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.
196 *Id.* at 70.

Table 12-84 Transmission facility outage request summary by planned duration: June 2024 through December 2025

	2024/2025 (12 months)		2025/2026 (7 months)	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	15,092	75.2%	11,503	70.8%
>5 & <=30	3,148	15.7%	2,860	17.6%
>30	1,840	9.2%	1,883	11.6%
Total	20,080	100.0%	16,246	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 12-85.[197]

The purpose of the rules defined in Table 12-85 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.[198]

Table 12-85 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	Before 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 12-86 shows a summary of requests by received status. In the first seven months of the 2025/2026 planning period, 34.3 percent of outage requests received were late. In the 2024/2025 planning period, 40.5 percent of outage requests received were late.

Table 12-86 Transmission facility outage requests by received status: June 2024 through December 2025

	2024/2025 (12 months)				2025/2026 (7 months)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	9,558	5,534	15,092	36.7%	7,876	3,627	11,503	31.5%
>5 & <=30	1,684	1,464	3,148	46.5%	1,861	999	2,860	34.9%
>30	705	1,135	1,840	61.7%	934	949	1,883	50.4%
Total	11,947	8,133	20,080	40.5%	10,671	5,575	16,246	34.3%

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.[199]

197 See PJM, "Manual 3: Transmission Operations," Rev. 69 (Nov. 20, 2025).
198 See "Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).
199 See PJM, "Manual 3: Transmission Operations," Rev. 69 (Nov. 20, 2025). 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).

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.[200] Table 12-87 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the first seven months of the 2025/2026 planning period, 10.4 percent were for emergency outages. Of all outage requests scheduled to occur in the 2024/2025 planning period, 12.1 percent were for emergency outages.

Table 12-87 Transmission facility outage requests by emergency: June 2024 through December 2025

	2024/2025 (12 months)				2025/2026 (7 months)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	1,709	13,383	15,092	11.3%	1,216	10,287	11,503	10.6%
>5 & <=30	400	2,748	3,148	12.7%	232	2,628	2,860	8.1%
>30	325	1,515	1,840	17.7%	238	1,645	1,883	12.6%
Total	2,434	17,646	20,080	12.1%	1,686	14,560	16,246	10.4%

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."[201]

After PJM determines that a late request may cause congestion, PJM informs the transmission owner of solutions available to eliminate the congestion. For example, if a generator planned or maintenance outage request is contributing to the congestion, PJM can request that the generation owner defer the outage. If no solutions are available, PJM may require the transmission owner to reschedule or cancel the outage.

Table 12-88 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the first seven months of the 2025/2026 planning period, 9.0 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.7 percent (55 out of 1,467) were denied by PJM in the first seven months of the 2025/2026 planning period and 16.5 percent (242 out of 1,467) were cancelled (Table 12-90). Of all outage requests submitted to occur in the 2024/2025 planning period, 9.1 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 5.2 percent (94 out of 1,818) were denied by PJM in the 2024/2025 planning period and 20.5 percent (373 out of 1,818) were cancelled (Table 12-90).

Table 12-88 Transmission facility outage requests by congestion: June 2024 through December 2025

	2024/2025 (12 months)				2025/2026 (7 months)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	1,242	13,850	15,092	8.2%	901	10,602	11,503	7.8%
>5 & <=30	388	2,760	3,148	12.3%	357	2,503	2,860	12.5%
>30	188	1,652	1,840	10.2%	209	1,674	1,883	11.1%
Total	1,818	18,262	20,080	9.1%	1,467	14,779	16,246	9.0%

200 PJM, "Manual 3: Transmission Operations," Rev. 69 (Nov. 20, 2025).
201 PJM added this definition to Manual 38 in February 2017. PJM, "Manual 38: Operations Planning," Rev. 19 (Jan. 23, 2025).

Table 12-89 shows the outage requests summary by received status, congestion status and emergency status. In the first seven months of the 2025/2026 planning period, 24.1 percent of requests were submitted late and were nonemergency while 1.2 percent of requests (232 out of 16,246) were late, nonemergency, and expected to cause congestion. In the 2024/2025 planning period, 28.5 percent of requests were submitted late and were nonemergency while 1.6 percent of requests (325 out of 20,080) were late, nonemergency, and expected to cause congestion.

Table 12-89 Transmission facility outage requests by received status, emergency and congestion: June 2024 through December 2025

		2024/2025 (12 months)				2025/2026 (7 months)			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent of Total	Congestion Expected	No Congestion Expected	Total	Percent of Total
Late	Emergency	121	2,286	2,407	12.0%	84	1,570	1,654	10.2%
	Non Emergency	325	5,401	5,726	28.5%	232	3,689	3,921	24.1%
On Time	Emergency	2	25	27	0.1%	4	28	32	0.2%
	Non Emergency	1,370	10,550	11,920	59.4%	1,147	9,492	10,639	65.5%
Total		1,818	18,262	20,080	100.0%	1,467	14,779	16,246	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.[202] Table 12-90 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 12-90. Table 12-90 shows that of all the outage requests that were expected to cause congestion, 3.7 percent (55 out of 1,467) were denied by PJM in the first seven months of the 2025/2026 planning period, 53.2 percent were complete and 16.5 percent (242 out of 1,467) were cancelled. Of all the outage requests that were expected to cause congestion, 5.2 percent (94 out of 1,818) were denied by PJM in the 2024/2025 planning period, 67.5 percent were complete and 20.5 percent (373 out of 1,818) were cancelled.

Table 12-90 Transmission facility outage requests by processed status[203]: June 2024 through December 2025

		2024/2025 (12 months)						2025/2026 (7 months)					
Received Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	12	104	3	1	121	86.0%	7	72	4	1	84	85.7%
	Non Emergency	63	221	10	28	325	68.0%	44	139	29	14	232	59.9%
On Time	Emergency	1	1	0	0	2	50.0%	0	4	0	0	4	100.0%
	Non Emergency	297	902	94	65	1,370	65.8%	191	566	337	40	1,147	49.3%
Total		373	1,228	107	94	1,818	67.5%	242	781	370	55	1,467	53.2%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM tariff and PJM manuals.[204] The On Time or Late status affects the way in which PJM addresses the potential to exceed transmission limits. Table 12-90 shows that in the first seven months of the 2025/2026 planning period, 232 nonemergency outage requests were submitted late and expected to cause congestion. The expected impact on congestion and the options for controlling that congestion is the basis for PJM's treatment of late outage requests.

The definition of this congestion analysis in the PJM manuals is about physical limits and not about economic congestion. PJM approves on time outages based solely on whether limits are exceeded and available controlling actions, without regard to the resulting level of economic congestion. The MMU recommends that PJM draft a definition of the congestion analysis required for transmission outage requests and associated triggers, including

202 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2019).
203 The number of denied transmission outage requests is lower than calculated by PJM the MMU includes only the transmission outage requests with "Denied" as a final status, while PJM included both transmission outage requests with "Denied" as a final status and transmission outage requests with "Denied" as an intermediate status.
204 OA Schedule 1 § 1.9.2.

both the extent of overloaded facilities and the level of economic congestion, to include in PJM manuals after appropriate review with appropriate rules for on time and late outage requests.[205]

The treatment by PJM and Dominion Virginia Power of the outage for the Lanexa – Dunnsville Line illustrates some of the issues with the current process. The outage was submitted and delayed more than once. It is not clear that PJM's analysis of expected congestion identified or highlighted the magnitude of the economic impact. Dominion Virginia Power did not stage the outage so as to minimize market disruption and congestion. After high congestion costs of Greys Point - Harmony Village constraint and market participant manipulative behavior caused by the outage were identified by the end of January, on February 11, 2022 Dominion decided to temporarily terminate the outage in March in order to work on upgrading Greys Point, Harmony Village and White Stone path. The Greys Point - Harmony Village Line has not been binding since March 14, 2022. It indicates that if the market impact of the outage was identified during PJM outage analysis process and action was taken because of the analysis result, the high congestion costs and manipulative behavior could have been prevented.

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-91 is a summary of all the outage requests planned for the 2024/2025 planning period and the first seven months of the 2025/2026 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 2025/2026 planning period, 21.8 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 8.9 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2024/2025 planning period, 30.1 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 12.5 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs.[206]

Table 12-91 Rescheduled and cancelled transmission outage requests: June 2024 through December 2025

	2024/2025 (12 months)					2025/2026 (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	15,092	3,054	20.2%	2,150	14.2%	11,503	1,784	15.5%	1,229	10.7%
>5 & <=30	3,148	1,792	56.9%	260	8.3%	2,860	1,006	35.2%	151	5.3%
>30	1,840	1,195	64.9%	96	5.2%	1,883	748	39.7%	72	3.8%
Total	20,080	6,041	30.1%	2,506	12.5%	16,246	3,538	21.8%	1,452	8.9%

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.[207] 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

205 "PJM Manual 38: Operations Planning," Rev. 19 (Jan. 23, 2025). p 21. Manual 38 states: "The outages are analyzed for reliability and expected off-costs. Each outage is studied and any constraints (actual or facility/contingency pair) trending toward a limit or exceeding a limit is noted in eDART. The trending or exceeding of a limit in the study is referred to as potential "congestion". The limit may be any or a combination of thermal, voltage, or stability issues. If there is an expected constraint, PJM will mark the corresponding eDART ticket as "congestion expected". The "congestion expected" flag is used to indicate a potential issue that may occur in the Day-Ahead Market or in Real-time Operations. If there are non-cost controlling actions, changes to the generation pattern, or changes to system conditions, the noted congestion may not occur in the Day-Ahead Market or in Real-time Operations. For "On-time" outages, PJM ensures the constraint can be mitigated by applying both non-cost and off-cost operations. If there are no limit exceedances as a result, the outage will be approved. For "Late" outages, PJM will apply only non-cost operations."

206 The number of tickets in each category can change over time. For example, a ticket initially classified as canceled or denied may be resubmitted at a later date for a different date range. Once approved the resubmitted ticket overrides the original ticket dates and details.

207 PJM, "Manual 3: Transmission Operations," Rev. 69 (Nov. 20, 2025).

to the revised month in which the outage will occur.[208] 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, create options for late requests based on the reasons, and apply the modified rules for late submissions to any such outages. The MMU recommends that PJM create options for treatment of late outages. The current rules apply more stringent rules, based on controlling actions, to late outages without distinguishing among reasons for late outages.

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-85) 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 12-92 shows equipment outages by the equipment instead of by outage request.

Table 12-92 shows that there were 8,559 transmission equipment planned outages in the first seven months of the 2025/2026 planning period, of which 1,251 or 14.6 percent were longer than 30 days, and of which 119 or 1.4 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

Table 12-92 Transmission equipment outages: June 2024 through December 2025

		2024/2025 (12 months)		2025/2026 (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	1,586	12.3%	1,251	14.6%
	Yes	251	1.9%	119	1.4%
<= 30		11,045	85.7%	7,219	84.0%
Total		12,882	100.0%	8,589	100.0%

Table 12-93 shows the details of long duration (> 30 days) outages when combining the duration of the outage requests for the same equipment.[209] The actual duration of scheduled outages would be longer than 30 days if the duration of the outage requests was 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 2025/2026 planning period, with an effective duration greater than a month and shorter than two months, there were 38 outages with a combined duration longer than 30 days.[210]

208 *Id.*
209 A transmission facility is modeled as equipment in the EMS model. Equipment has three identifiers: location (B1), voltage level (B2) and equipment name (B3). The types of equipment include, for example, lines, transformers, and capacitors. There can be multiple outage requests associated with the same equipment.
210 The length of a planned equipment outage can be modified by editing an existing ticket for the equipment outage or by adding new equipment outage tickets for the same equipment.

Table 12-93 Transmission equipment outages by effective duration: June 2024 through December 2025

	2024/2025 (12 months)		2025/2026 (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	9	3.6%	8	6.7%
>31 & <=62	33	13.1%	38	31.9%
>62 & <=93	18	7.2%	26	21.8%
>93	191	76.1%	47	39.5%
Total	251	100.0%	119	100.0%

Transmission Facility Outage Analysis for the FTR Market

Transmission facility outages affect the price and quantity outcomes of FTR Auctions. The purpose of the rules governing outage reporting is to ensure that outages are known with enough lead time prior to FTR Auctions so that market participants can understand market conditions and PJM can accurately model market conditions.

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

Annual FTR Market

The Annual FTR Market includes the Annual ARR Allocation and the Annual FTR Auction. When determining transmission outages to be modeled in the simultaneous feasibility test used in the Annual FTR Market, PJM considers all outages with planned duration longer than or equal to two 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.[211]

In the first seven months of the 2025/2026 planning period, 166 outage requests were included in the annual FTR market outage list and 11,972 outage requests were not included.[212] In the 2024/2025 planning period, 436 outage requests were included in the annual FTR market outage list and 19,644 outage requests were not included. Table 12-94, Table 12-95, Table 12-96 and Table 12-97 show the summary information on the modeled outage requests and Table 12-98 and Table 12-99 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-94 shows that 23.2 percent of the outage requests modeled in the Annual FTR Market for the first seven months of the 2025/2026 planning period had a planned duration of less than two weeks and that 13.9 percent of the outage requests (23 out of 166) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 23.2 percent of the outage requests modeled in the Annual FTR Market for the 2024/2025 planning period had a planned duration of less than two weeks and that 17.9 percent of the outage requests (78 out of 436) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

Table 12-94 Annual FTR market modeled transmission facility outage requests by received status: June 2024 through December 2025

	2024/2025 (12 months)				2025/2026 (7 months)			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	93	8	101	23.2%	18	5	23	13.9%
>=2 weeks & <2 months	142	20	162	37.2%	36	2	38	22.9%
>=2 months	123	50	173	39.7%	80	25	105	63.3%
Total	358	78	436	100.0%	134	32	166	100.0%

211 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.
212 PJM's treatment of transmission outages in the FTR models is discussed in the *2024 Quarterly State of the Market Report for PJM: January through June*, Section 13: FTRs and ARRs, Supply and Demand.

Table 12-95 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 2025/2026 planning period were emergency outages. Three of the modeled outages expected to occur in the 2024/2025 planning period were emergency outages.

Table 12-95 Annual FTR market modeled transmission facility outage requests by emergency: June 2024 through December 2025

		2024/2025 (12 months)				2025/2026 (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	93	93	100.0%	0	18	18	100.0%
	>=2 weeks & <2 months	1	141	142	99.3%	0	36	36	100.0%
	>=2 months	0	123	123	100.0%	0	80	80	100.0%
	Total	1	357	358	99.7%	0	134	134	100.0%
Late	<2 weeks	0	8	8	100.0%	0	5	5	100.0%
	>=2 weeks & <2 months	0	20	20	100.0%	0	2	2	100.0%
	>=2 months	3	47	50	94.0%	2	23	25	92.0%
	Total	3	75	78	96.2%	2	30	32	93.8%

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 12-96 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 2025/2026 planning period and submitted late, 12.5 percent (4 out of 32) were expected to cause congestion. Of all the annual FTR market modeled outages expected to occur in the 2024/2025 planning period and submitted late, 20.5 percent (16 out of 78) were expected to cause congestion.

Table 12-96 Annual FTR market modeled transmission facility outage requests by congestion: June 2024 through December 2025

		2024/2025 (12 months)				2025/2026 (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	23	70	93	24.7%	6	12	18	33.3%
	>=2 weeks & <2 months	33	109	142	23.2%	21	15	36	58.3%
	>=2 months	32	91	123	26.0%	20	60	80	25.0%
	Total	88	270	358	24.6%	47	87	134	35.1%
Late	<2 weeks	2	6	8	25.0%	1	4	5	20.0%
	>=2 weeks & <2 months	4	16	20	20.0%	1	1	2	50.0%
	>=2 months	10	40	50	20.0%	2	23	25	8.0%
	Total	16	62	78	20.5%	4	28	32	12.5%

Table 12-97 shows that 15.8 percent of outage requests modeled in the annual FTR market for the first seven months of the 2025/2026 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 24.1 percent for the 2024/2025 planning period. Table 12-97 also shows that 11.4 percent of outages requests modeled in the Annual FTR Market for the first seven months of the 2025/2026 planning period and with a duration of two months or longer were cancelled, compared to 19.1 percent for the 2024/2025 planning period.

Table 12-97 Annual FTR market modeled transmission facility outage requests by processed status: June 2024 through December 2025

		2024/2025 (12 months)		2025/2026 (7 months)	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	8	7.9%	1	4.3%
	Denied	1	1.0%	0	0.0%
	Approved	0	0.0%	2	8.7%
	Cancelled	28	27.7%	9	39.1%
	Revised	1	1.0%	0	0.0%
	Active	0	0.0%	0	0.0%
	Completed	63	62.4%	11	47.8%
	Total	101	100.0%	23	100.0%
>=2 weeks & <2 months	In Progress	25	15.4%	10	26.3%
	Denied	0	0.0%	1	2.6%
	Approved	2	1.2%	0	0.0%
	Cancelled	39	24.1%	6	15.8%
	Revised	0	0.0%	0	0.0%
	Active	0	0.0%	0	0.0%
	Completed	96	59.3%	21	55.3%
	Total	162	100.0%	38	100.0%
>=2 months	In Progress	24	13.9%	22	21.0%
	Denied	1	0.6%	1	1.0%
	Approved	1	0.6%	1	1.0%
	Cancelled	33	19.1%	12	11.4%
	Revised	0	0.0%	0	0.0%
	Active	9	5.2%	32	30.5%
	Completed	105	60.7%	37	35.2%
	Total	173	100.0%	105	100.0%
Total Cancelled		100	22.9%	27	16.3%
Grand Total		436		166	

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 2025/2026 planning period, 166 outage requests were modeled and 11,972 outage requests were not modeled in the Annual FTR Market. In the 2024/2025 planning period, 436 outage requests were modeled and 19,640 outage requests were not modeled in the Annual FTR Market.

Table 12-98 shows that 11.2 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 or rescheduled after the Annual FTR Auction bidding opening date in the first seven months of the 2025/2026 planning period, compared to 20.3 percent in the 2024/2025 planning period.

Table 12-98 Transmission facility outage requests not modeled in Annual FTR Auction: June 2024 through December 2025

	2024/2025 (12 months)						2025/2026 (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	1,816	8,471	82.3%	202	6,162	96.8%	1,700	4,069	70.5%	194	3,817	95.2%
>=2 weeks & <2 months	667	395	37.2%	164	861	84.0%	635	124	16.3%	123	502	80.3%
>=2 months	191	49	20.4%	252	414	62.2%	206	26	11.2%	322	254	44.1%
Total	2,674	8,915	76.9%	618	7,437	92.3%	2,541	4,219	62.4%	639	4,573	87.7%

Table 12-99 shows that 90.2 percent of late outage requests that were submitted after the Annual FTR Auction bidding opening date, were not modeled in the Annual FTR Auction, and had a duration longer than or equal to two months, were completed in the first seven months of the 2025/2026 planning period. It also shows that 90.6 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 active or completed in the 2024/2025 planning period.

Table 12-99 Late transmission facility outage requests: June 2024 through December 2025

	2024/2025 (12 months)			2025/2026 (7 months)		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	5,210	6,162	84.6%	3,243	3,817	85.0%
>=2 weeks & <2 months	725	861	84.2%	440	502	87.6%
>=2 months	375	414	90.6%	229	254	90.2%
Total	6,310	7,437	84.8%	3,912	4,573	85.5%

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 create options for late requests based on the reasons, and modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction opening date, based on those options.

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.[213] Table 12-100 and Table 12-101 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-102 and Table 12-103 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

Table 12-100 shows that on average, 28.6 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the first seven months of the 2025/2026 planning period. On average, 28.8 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 2024/2025 planning period.

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

Table 12-100 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: June 2024 through December 2025

	2024/2025				2025/2026			
Month	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
Jun	272	134	406	33.0%	296	126	422	29.9%
Jul	154	100	254	39.4%	183	116	299	38.8%
Aug	211	101	312	32.4%	201	107	308	34.7%
Sep	488	175	663	26.4%	527	151	678	22.3%
Oct	542	190	732	26.0%	567	167	734	22.8%
Nov	511	197	708	27.8%	414	140	554	25.3%
Dec	359	127	486	26.1%	268	98	366	26.8%
Jan	239	80	319	25.1%				
Feb	275	103	378	27.2%				
Mar	477	158	635	24.9%				
Apr	515	192	707	27.2%				
May	482	203	685	29.6%				
Average	377	147	524	28.8%	351	129	480	28.6%

Table 12-101 shows that on average, 17.6 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the first seven months of the 2025/2026 planning period. On average, 20.1 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2024/2025 planning period.

Table 12-101 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: June 2024 through December 2025

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Percent Cancelled
2024/2025	Jun	28	13	16	93	0	90	166	406	22.9%
	Jul	22	8	15	41	0	97	71	254	16.1%
	Aug	18	16	10	68	0	81	119	312	21.8%
	Sep	70	7	30	111	0	192	253	663	16.7%
	Oct	60	1	19	174	2	209	267	732	23.8%
	Nov	63	5	23	124	0	185	308	708	17.5%
	Dec	40	16	8	101	0	101	220	486	20.8%
	Jan	41	9	9	67	0	110	83	319	21.0%
	Feb	27	6	11	79	0	116	139	378	20.9%
	Mar	62	5	19	139	1	164	245	635	21.9%
	Apr	61	6	18	133	0	200	289	707	18.8%
	May	43	11	17	135	1	123	355	685	19.7%
	Average	45	9	16	105	0	139	210	524	20.1%
2025/2026	Jun	50	20	15	72	0	91	174	422	17.1%
	Jul	29	17	10	52	0	97	94	299	17.4%
	Aug	39	9	8	49	0	84	119	308	15.9%
	Sep	73	6	25	128	1	204	241	678	18.9%
	Oct	76	2	31	160	1	204	260	734	21.8%
	Nov	38	5	12	120	0	161	218	554	21.7%
	Dec	32	5	5	86	0	81	157	366	23.5%
	Average	48	13	15	75	0	119	157	427	17.6%

Table 12-102 shows that on average, 13.3 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 2025/2026 planning period, compared to 14.0 percent in the 2024/2025 planning period. On average, 60.0 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 2025/2026 planning period, compared to 57.2 percent in the 2024/2025 planning period.

Table 12-102 Transmission facility outage requests not modeled in Monthly Balance of Planning Period FTR Auction: June 2024 through December 2025

	2024/2025						2025/2026					
	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	684	151	18.08%	376	566	60.1%	697	146	17.32%	426	730	63.1%
Jul	438	152	25.76%	304	541	64.0%	456	135	22.84%	342	654	65.7%
Aug	453	107	19.11%	296	482	62.0%	441	104	19.08%	351	629	64.2%
Sep	982	106	9.74%	335	530	61.3%	1,045	90	7.93%	405	597	59.6%
Oct	1,115	129	10.37%	412	733	64.0%	1,204	83	6.45%	468	733	61.0%
Nov	717	81	10.15%	444	529	54.4%	920	92	9.09%	537	611	53.2%
Dec	597	122	16.97%	428	487	53.2%	852	96	10.13%	486	547	53.0%
Jan	1,109	135	10.85%	1,282	546	29.9%						
Feb	626	101	13.89%	410	530	56.4%						
Mar	1,219	142	10.43%	433	785	64.4%						
Apr	1,308	145	9.98%	505	695	57.9%						
May	1,115	154	12.14%	511	738	59.1%						
Average	864	127	13.96%	478	597	57.2%	802	107	13.26%	431	643	60.0%

Table 12-103 shows that on average, 68.5 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 completed in the first seven months of the 2025/2026 planning period, compared to 67.0 percent in the 2024/2025 planning period.

Table 12-103 Late transmission facility outage requests: June 2024 through December 2025

	2024/2025			2025/2026		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	361	566	63.8%	494	730	67.7%
Jul	380	541	70.2%	421	654	64.4%
Aug	359	482	74.5%	482	629	76.6%
Sep	360	530	67.9%	386	597	64.7%
Oct	472	733	64.4%	468	733	63.8%
Nov	367	529	69.4%	454	611	74.3%
Dec	324	487	66.5%	372	547	68.0%
Jan	348	546	63.7%			
Feb	341	530	64.3%			
Mar	496	785	63.2%			
Apr	438	695	63.0%			
May	537	738	72.8%			
Average	399	597	67.0%	440	643	68.5%

Table 12-103 shows that only 1.4 percent of all outage requests were modeled in the Annual FTR Auction in the first seven months of the 2025/2026 planning period, and 2.2 percent were modeled in the 2024/2025 planning period. For Monthly FTR Auctions in the first seven months of the 2025/2026 planning period, an average of 22.3 percent of all outage requests were modeled, and 25.7 percent were modeled in the 2024/2025 planning period.

Table 12-104 FTR market modeled transmission facility outage requests: June 2024 through December 2025

	2024/2025 (12 months)			2025/2026 (7 months)		
Planned Duration	Annual Modeled	Monthly Modeled	Total	Annual Modeled	Monthly Modeled	Total
<2 weeks	101	3,220	3,321	23	1,578	1,601
>=2 weeks & <2 months	162	1,305	1,467	38	716	754
>=2 months	173	644	817	105	409	514
Total	436	5,169	5,605	166	2,703	2,869
All outage requests			20,080			12,138
Percent of Modeled	2.2%	25.7%	27.9%	1.4%	22.3%	23.6%

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.[214]

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 in eDART. 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 June 30, 2025, Figure 12-7 shows that: there were 278 approved or active outages seen by market participants before the day-ahead market was closed; there were 363 outage requests included in the day-ahead market model; there were 344 outage requests included in both sets of outages; there were 85 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 65 outage requests included in day-ahead market model but not available to market participants prior to the day-ahead market.

214 PJM, "Manual 3: Transmission Operations," Rev. 69 (Nov. 20, 2025).

Figure 12-7 Illustration of day-ahead market analysis: June 30, 2025

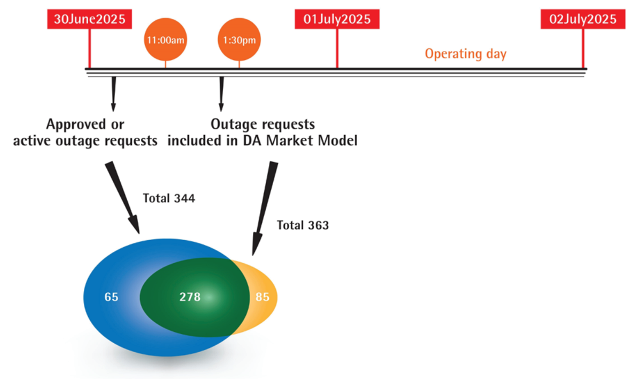


Figure 12-8 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.[215] Figure 12-8 shows that the number of outages modeled in the day-ahead market during the spring and fall has increased since 2021 (blue line), but many of these outages were not visible to market participants (gray line).

Figure 12-8 Approved or active outage requests: 2015 through 2025

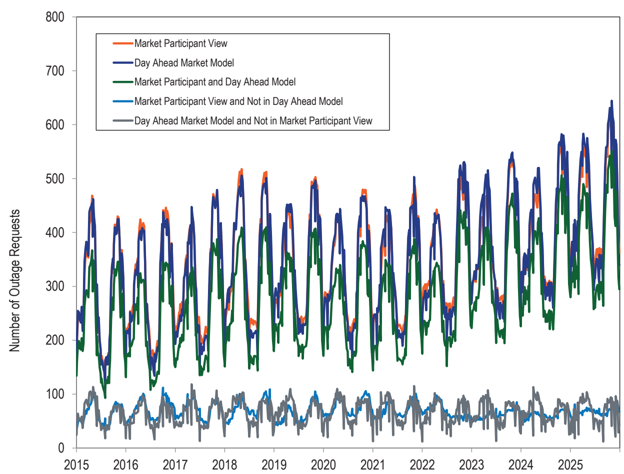


Figure 12-9 compares the weekly average number of outages included in the day-ahead market with the outages that actually occurred during the operating day. Figure 12-9 shows that beginning in 2021, the weekly average number of outages included in the day-ahead

215 The analysis and figures in this report (Figure 12-8, Figure 12-9, and Figure 12-10) are based on a revised method (relative to the method used in prior State of the Market Reports) that correctly accounts for outages that did not, at the time the outage was active, have an end date specified on the outage ticket.

market (dark blue line) was higher in the spring and fall than previous years, but many of these outages did not actually occur in the real time market (gray line). For example, some outages were scheduled to occur in day-ahead based on the information provided in eDART, but were cancelled or rescheduled in real time due to weather, equipment availability, reliability concerns, or the discretion of the transmission owner.

Figure 12-9 Day-ahead market model outages: 2015 through 2025

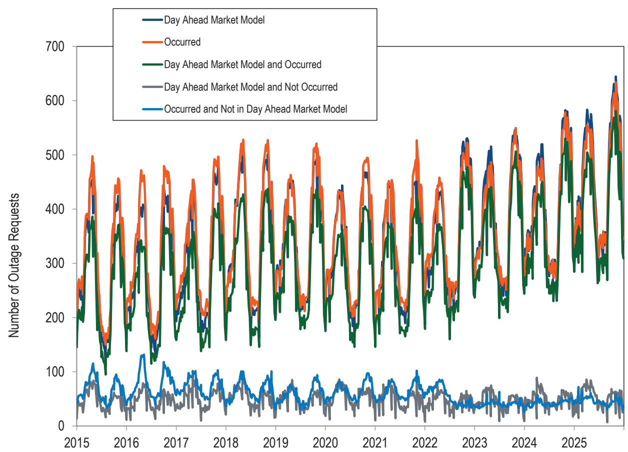


Figure 12-10 compares the weekly average number of active or approved outages for which information was visible to market participants through eDART prior to the close of the day-ahead market with the outages that actually occurred in the real-time market during the operating day. Figure 12-10 shows the number of outages visible to market participants in eDART, but not actually occurring in the real-time market, varies from less than 10 to over 100 in any given week.

Figure 12-10 Approved or active outage requests: 2015 through 2025

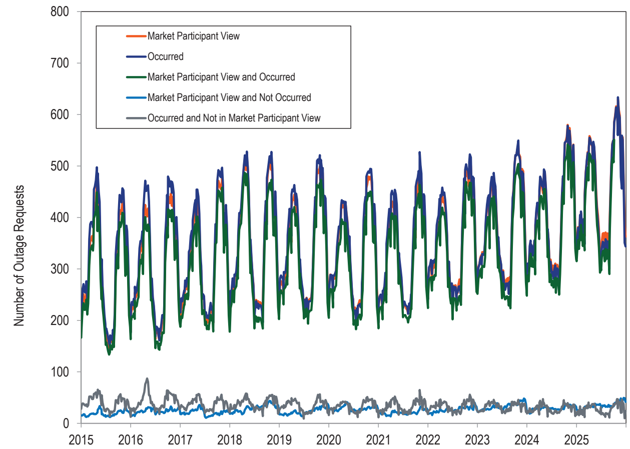


Figure 12-8, Figure 12-9, and Figure 12-10 show that on a weekly average basis, for the full years 2023, 2024, and 2025, the active or approved outages for which information was visible to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent.