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State Roles and Functions in Regional Large Load Forecasting

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States are playing an increasingly important role in reviewing the large load forecasts that transmission utilities provide to regional transmission organizations (RTOs), which RTOs use in regional resource adequacy and transmission planning. This technical brief provides an overview of emerging state roles and functions in regional large load forecasting, focusing on PJM and briefly examining other regions as well.

PJM implemented significant changes to its long-term load forecasting in early 2026, including opportunities for state regulatory review of large load adjustments. This brief examines state review in the context of PJM's large load forecast adjustment process and explores the types of feedback that state agencies and other regulatory authorities might provide in their reviews.

The brief is organized into four sections:

- **Background** – provides an overview of PJM's long-term load forecasting process, interactions between load interconnection and load forecasting, and how long-term load forecasts are used.
- **PJM's large load forecast adjustments** – describes PJM's large load forecast adjustment process and the role of relevant electric retail regulatory authorities (RERRAs) in reviewing large load forecast submissions by electric distribution companies (EDCs) and load serving entities (LSEs).
- **Large load forecasting and RERRA participation in other ISO/RTO regions** – describes RERRA roles in load forecasting in other independent system operators (ISOs) and RTOs.
- **Considerations for RERRA participation in PJM's load forecast adjustment process** – outlines considerations for RERRA participation in PJM's load forecast adjustments, how RERRAs might coordinate their participation, and potential clarifications, questions, and areas of feedback for PJM.

1. Background

This section provides background on PJM's long-term load forecast; its use in resource adequacy, transmission planning, interconnection; and its use in and implications for other recent PJM initiatives related to large loads and transmission planning.

1.1 PJM's Long-Term Load Forecast

Each year, PJM develops a 20-year forecast of hourly demand for each PJM zone.[1] This load forecast is based on a multi-variable regression model that incorporates weather conditions, economic drivers, trends in end-use

[1] Historically, PJM's load forecast appears to have been limited to coincident and non-coincident peak and annual energy demand. More recently, PJM appears to have moved to hourly load forecasts, consistent with a 2022 review of and recommendations to improve its load forecast model by Itron (*2022 PJM Model Review*). For more detail on PJM's load forecasting methods, see its *PJM Manual 19: Load Forecasting and Analysis*. The information in this section is based on revision 38 (effective date December 17, 2025) of Manual 19.

efficiency, distributed solar generation, and electric vehicles. PJM adjusts the load forecasts generated by its model to account for large load additions and peak shaving programs.

PJM uses historical weather data to simulate distributions of monthly non-coincident and coincident peak load forecasts for each zone. From this distribution, PJM selects median (50/50) and 10th percentile (90/10) values for each season to use in its resource adequacy mechanism and transmission planning and expansion.

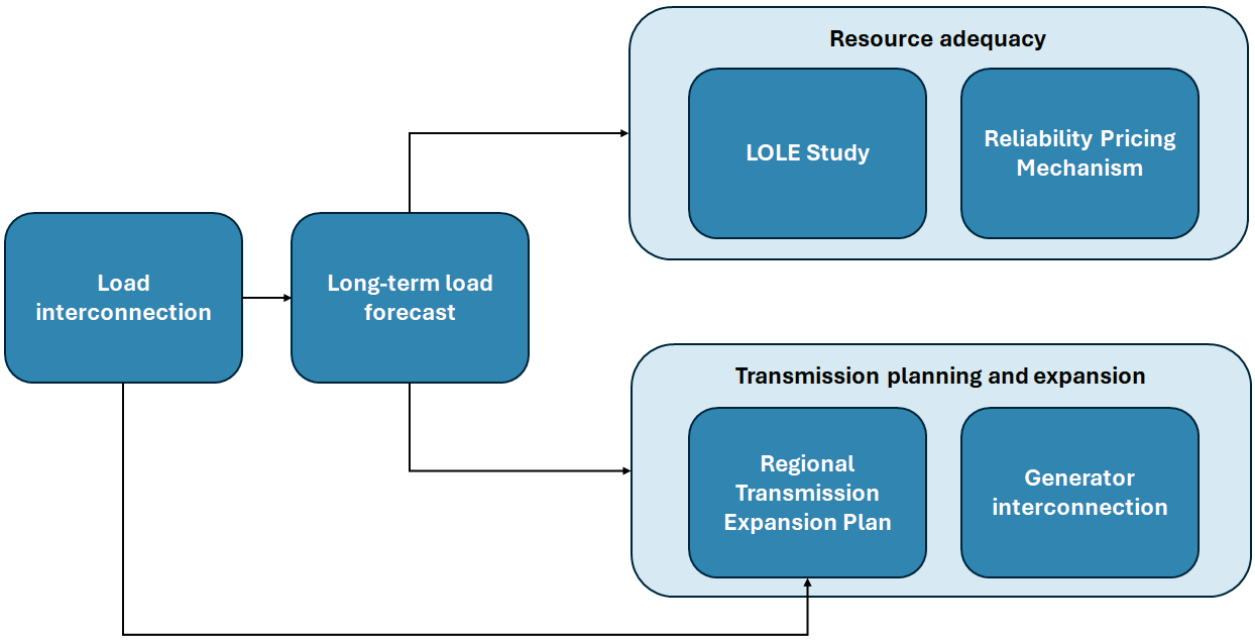
Changes to PJM's model and load forecast adjustments are reviewed by the Load Analysis Subcommittee and Planning Committee. Members of the Planning Committee may request a review of the load forecast.

1.2 Uses of PJM's Long-Term Load Forecast

PJM's uses its long-term load forecasts primarily as inputs to its resource adequacy mechanism and in transmission planning studies (Figure 1).

- **Resource adequacy** – as inputs to the loss-of-load expectation (LOLE) analysis in PJM's *LOLE Study* and to clear PJM's capacity auction – the Reliability Pricing Mechanism (RPM).
- **Transmission planning and expansion** – as inputs to transmission models used in PJM's Regional Transmission Expansion Plan (RTEP) and generator interconnection.

Figure 1. Key Uses of PJM's Long-Term Load Forecast in Resource Adequacy and Transmission Planning and Expansion, and Interactions Between Load Interconnection, Load Forecasting, and RTEP



Load interconnection, which is managed by transmission and distribution utilities, provides data inputs for large load adjustments, directly interacts with the RTEP process, and has a more indirect relationship with resource adequacy (see box, below).

Load Interconnection, Resource Adequacy, and Transmission Planning

A large load wishing to obtain electric service must first contact the transmission or distribution utility to request service. In PJM, the utility is responsible for conducting studies to determine what new infrastructure is needed to connect the load. Utilities typically do not evaluate the resource adequacy impacts of large loads in load interconnection, though in non-restructured states they may use interconnection requests and milestones in the load forecasts used in resource planning and procurement.

If the utility identifies reliability issues that require new transmission infrastructure, the utility submits these transmission projects ("supplemental projects") for review by Subregional RTEP Committees and, in some cases, the Transmission Expansion Advisory Committee (TEAC) under PJM's Attachment M-3 process. The M-3 process is separate from RTEP but feeds into it, as supplemental projects are included in the base transmission case in the next RTEP planning cycle. Utilities often do not provide detailed descriptions of how loads are modeled in load interconnection, making it difficult to determine the balance between large load-driven transmission issues that are addressed in RTEP versus being first addressed in load interconnection.*

* In general, it appears that most incremental, near-term reliability issues within a transmission utility's service territory that are caused by the addition of a new large load will be addressed through interconnection and supplemental projects, though larger, longer-term issues may be addressed through RTEP. For examples of utility interconnection guidelines, see those for AEP and Dominion.

In capacity markets and transmission planning, PJM uses load forecasts to identify resource and transmission needs. PJM allocates costs for the capacity auction and for transmission based on metered historical rather than forecasted demand.[2] Still, load forecasts have a significant influence on the timing, location, and magnitude of generation and transmission investments and thus on the costs that consumers eventually pay. The cost impact of inaccurate large load forecasts may be borne regionally rather than locally.[3]

1.3 PJM's Long-Term Load Forecast in Recent Initiatives[4]

Large load forecasts have implications for several other recent PJM initiatives, including:

- Reliability Resource Initiative (RRI) and Expedited Interconnection Track (EIT)
- Reliability backstop procurement (RBP)
- Bring-your-own new generation (BYONG)
- Non-firm transmission service

[2] Cost allocation for PJM's capacity market is covered in *PJM Manual 19: Load Forecasting and Analysis*; cost allocation for transmission is covered in *PJM Manual 14B: PJM Region Transmission Planning Process*.

[3] The extent to which cost shifting occurs as a result of load forecast error can often be subtle and related to the timing of changes in load ratio shares, which are determined by historical metered load rather than forecasted load. However, as a simple example consider two utilities (Utilities A and B) that allocate transmission costs based on load ratio share. Each utility accounted for 50% of metered load in the previous year and the annual transmission revenue requirement (ATRR) was $200 million, with each utility paying $100 million. Utility A forecasts a new 100 MW data center load that triggers new transmission needs and a $10 million increase in the ATRR. Utility B does not forecast any load growth. Permitting is more arduous than anticipated and the data center customer eventually cancels the project. Utility A and B still account for 50% of metered demand but the ATRR has increased to $210 million, increasing Utility B's share of the ATRR to $105 million.

[4] The terms and descriptions in this section are as of mid-June 2026. PJM has changed some of the terms and proposed approaches since.

- Connect and manage
- Long-term regional transmission planning (LTRTP)

In most instances, the key question for large load forecasts in these initiatives is which large loads to include in the forecasts used for generation procurement, capacity market clearing, and transmission planning.

Reliability resource initiative (RRI) and expedited interconnection track (EIT). RRI and EIT both aim to fast track generator interconnection to resolve projected near-term gaps in resource adequacy. RRI was a one-time initiative, approved by FERC in 2025, that allowed up to 50 projects to be fast tracked and join an already-in-progress interconnection study cluster.[5] EIT is a two-year initiative, approved by FERC in 2026, that will fast track generator projects that demonstrate an ability to achieve commercial operation within three years.[6] The need for both of these initiatives was informed by PJM's long-term load forecasts.

Reliability backstop procurement. RBP is a one-time, transitional process to procure generation capacity for large loads. The purpose is to close the gap between supply and demand in PJM's 2029 capacity auction.[7] RBP will have two phases. In the first phase, PJM will act as a facilitator for bilateral contracting between buyers and suppliers. In the second phase, PJM will procure any remaining capacity needed to meet a procurement target. The procurement target will be based on the 2026 forecast year's 2029 summer large load forecast for each zone minus the 2026 summer large load forecast. Although not explicitly stated, the large load forecast used to set the procurement target should be based on PJM's modifications to large load adjustments submitted by EDCs/LSEs ("firm" additions to the base load forecast, see Section 2.3). PJM clarifies that the load forecast used in RBP will exclude generation and load from entities that have fixed resource requirements (FRRs).[8]

Bring-your-own new generation. BYONG, approved by the PJM Board in the large load CIFP, creates a voluntary expedited interconnection process for large loads that are paired with new generation. PJM does not appear to have developed a proposal for BYONG yet.[9] In theory, BYONG load should not be included in the RBP's procurement target. However, BYONG load and generation should be included in the RPM and in RTEP except under specific circumstances.[10]

Non-firm transmission service. In December 2025, FERC directed PJM to file a proposal for non-firm transmission service for co-located load and generation.[11] Non-firm transmission service allows a customer to connect to the transmission system before all network upgrades required to reliably deliver power to the load

[5] For more on the RRI and its results, see "PJM Chooses 51 Generation Resource Projects To Address Near-Term Electricity Demand Growth," *PJM Inside Lines*, May 2, 2025.
[6] For more on the EIT, see PJM's *Expedited Interconnection Track Procedures*.
[7] PJM's *Critical Issue Fast Path – Reliability Backstop Procurement* provides more detail on its proposed approach.
[8] FRRs allow LSEs to opt-out of PJM's capacity market by demonstrating adequate resources to meet their peak coincident demand plus PJM's planning reserve margin. In delivery year 2026/2027, FRRs were equivalent to 11% of total capacity cleared in the RPM (see Tables 4 and 5 of PJM's *2026/2027 Base Residual Auction Report*).
[9] SPP's FERC-approved Load Limited Resource Interconnection Service (LLRIS) may provide a reference for the design of these kinds of expedited interconnection processes for co-located load and generation, though as described in Section 3 there are important differences between SPP and PJM.
[10] For the RPM, PJM may provide a pathway for large loads to opt-out of the PRM if they have adequacy generation to cover their peak demand plus the planning reserve margin. For RTEP, load and generation could be excluded from the load forecast if they are co-located and the large load customer has committed to limit withdrawals from the transmission system to a maximum (MW) amount.
[11] See Docket Nos. EL25-49-000 and EL25-49-001 (193 FERC ¶ 61,217) at https://elibrary.ferc.gov/eLibrary/.

are completed, with the customer agreeing to be curtailed when needed. PJM's proposal for non-firm transmission service remains in a stakeholder process.[12] Non-firm transmission service could be temporary or permanent. Co-located load and generation with permanent non-firm transmission service should not be included in the load forecast used in RPM or RTEP, though customers with temporary non-firm service should be included.

Connect and manage. Separately, PJM's Board approved a "connect and manage" mechanism that would allow loads – regardless of whether they have co-located generation – to come online before they have supporting generation or transmission if they agree to be curtailable when needed. Connect and manage is thus a broader form of non-firm generation and transmission service. PJM does not appear to have developed a proposal for connect and manage yet.[13] Like non-firm transmission service, the non-firm service resulting from connect and manage could be temporary or permanent, and should be included in the load forecasts used RPM or RTEP if temporary and should not be included if permanent.

Long-term regional transmission planning. LTRTP is PJM's Order 1920-compliant transmission planning process, which PJM submitted to FERC in December 2025.[14] PJM's proposal did not describe whether and how large load forecast adjustments would be included in the load forecast or in the scenarios used in the LTRTP's identification of new transmission needs.[15]

1.4 Potential Impacts of FERC's Show Cause Order on PJM"s Large Load Adjustment Process

On June 18, 2026, FERC ordered PJM and its member transmission owners to show cause, under section 206 of the Federal Power Act, why its existing tariff is just and reasonable without addressing several issues related to large loads, and to explain how they would revise the tariff if FERC were to find it unjust and unreasonable.[16] The first two of these issues may have significant implications for PJM's large load adjustment process:

(a) "the application process, study procedures, and ongoing operational requirements that apply to Eligible Customers seeking transmission service on behalf of large loads;

(b) additional transparency concerning the Network Upgrade costs to provide transmission service to Eligible Customers on behalf of large loads, a *pro forma* cost recovery agreement between PJM, the relevant transmission owner and Eligible Customer taking transmission service on behalf of the large load to mitigate the risk of cost shifting among transmission customers, and a mechanism to ensure such payments are appropriately credited towards transmission owners' transmission revenue requirements consistent with the Commission's cost-of-service regulations."

[12] PJM's initial proposal received significant pushback from stakeholders. See Ethan Howland, "PJM data center colocation plan takes fire from Vistra, data center group, others," *Utility Dive*, March 27, 2026.
[13] Again, SPP's proposed conditional high impact large load (CHILL) service might provide a reference.
[14] See PJM's compliance filing for more detail on its proposal.
[15] Presumably, only firm adjustments would be included in the Core LT Needs scenarios, whereas non-firm adjustments could be included in the Additional LT Needs scenarios.
[16] The two additional issues in the order were: "(c) transmission services that reflect Eligible Customers taking transmission service on behalf of flexible large loads that are willing and able to limit their use of the transmission system under certain conditions; and (d) the rates, terms, and conditions of service applicable to interconnection customers serving electrically proximate large load or co-located load." See FERC's June 18, 2026 Order Instituting Proceeding with PJM and its member transmission owners.

There are multiple ways in which PJM and member transmission owners could comply with the show cause order, ranging from more incremental changes that build upon the existing process to larger, structural changes in PJM's load interconnection and load forecast adjustment processes. The show cause order could also lead to changes in the risks of large load forecast error, for instance by direct assigning a larger share of interconnection facility and transmisison costs to interconnecting large loads. In thinking through RERRA roles and functions in PJM's large load forecast adjustments, it will be helpful to keep in mind this show cause order and how it might shape the adjustment process going forward.

2. PJM's Large Load Forecast Adjustments

PJM's large load adjustment process incorporates load growth that is not captured in forecast models into its long-term load forecast. PJM requests adjustments from EDCs/LSEs each year and modifies these adjustments to account for uncertainty before including in its long-term load forecast.

Large Load Forecast "Adjustments"

Language around PJM's load forecast adjustments can be confusing. PJM uses the term "adjustment" to refer to the submissions of large load forecasts* from EDCs/LSEs, because these forecasts are adjustments to PJM's base load forecasts. However, "adjustment" could also refer to PJM's subsequent modifications to the large load forecasts it receives from EDCs/LSEs. For clarity, we use the term "adjustment" to refer to EDC/LSE large load forecasts and "modification" to refer to PJM's changes to those forecasts.*

* PJM typically refers to large load forecasts as "demand requests." PJM also appears to use the term "modification" to refer to its downward revisions to EDC/LSE demand requests.

Before 2022, forecast adjustments through this process were relatively small – around 1 GW or less (Figure 2, below).[17] However, since 2022 they have increased significantly, especially in the 2025 and 2026 load forecasts (Figure 2). PJM's 2021 load forecast[18] had almost no large load growth from 2022 to 2036. By contrast, for PJM's 2026 load forecast summer peak demand adjustments were 11 GW for year 2026, 39 GW for 2030, 69 GW for 2035, 83 GW for 2040, and 87 GW for the last year of the load forecast in 2046. For reference, PJM's summer peak demand in 2025 was 154 GW.[19]

[17] The adjustments in the first part of this section draw on Table B-9 in PJM's *Long-Term Load Forecast Report* series and appear to include upward and downward adjustments for large loads and downward adjustments for voltage optimization. The first year in which PJM had a substantial upward adjustment was in the 2014 load forecast, due to data center growth in the Dominion zone.
[18] The year here refers to the first year of the forecast. PJM releases its *Long-Term Load Forecast Report* in January of the first year covered under the forecast. For instance, the 2021 report was released in January 2021 and 2021 is the first year covered under the forecast.
[19] This value is from the Weather Normalized Peaks spreadsheet.

Figure 2. Large Load Adjustments to the PJM Long-Term Load Forecast, Forecast Years 2009-2026

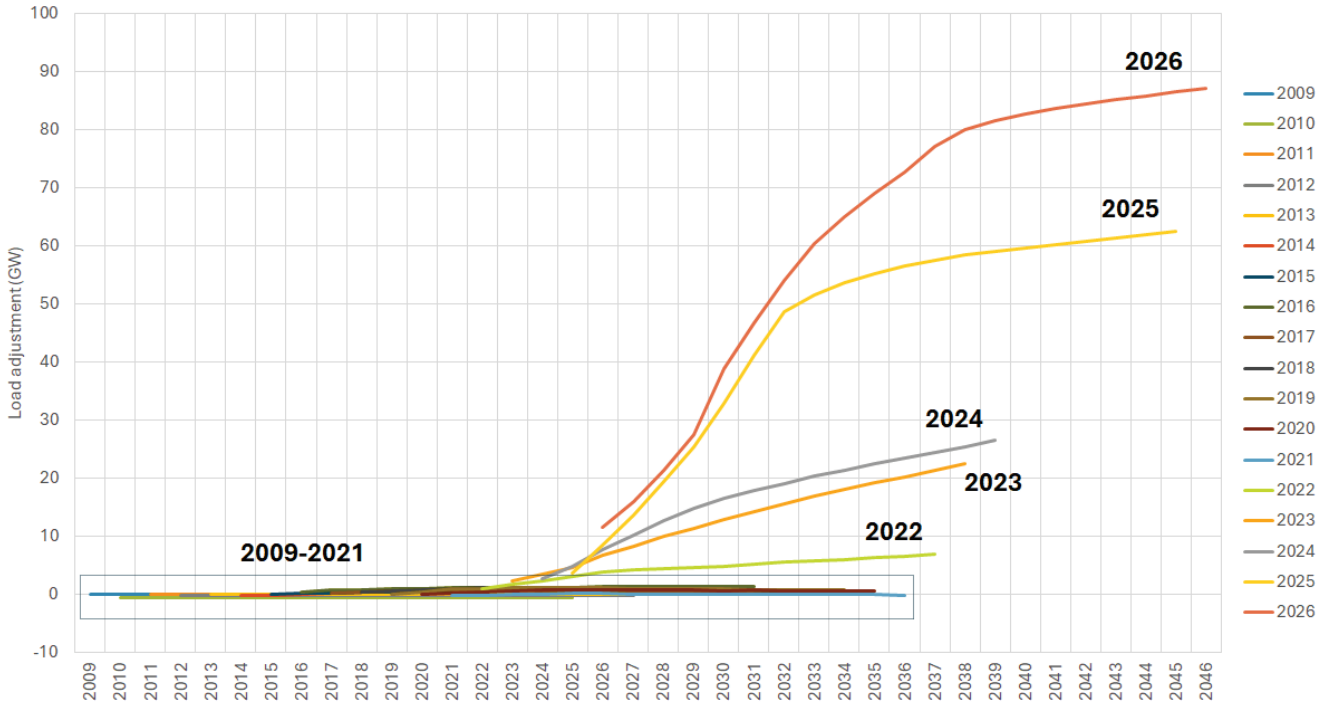


Figure notes and source: Each series in Figures 2 and 3 is a 15-year or 20-year load forecast. The first point in the series is the year of the forecast. For instance, the 2026 forecast begins in 2026 and extends over 20 years, from 2026 to 2046. PJM appears to have moved from a 15-year to a 20-year forecast in 2025. All data are from PJM's *Long-Term Load Forecast Report* series (historical reports available under "Previous Reports").

2.1 Large Load Adjustment Process and RERRA Review

Historically, PJM has solicited large load adjustments from EDCs/LSEs on an annual basis. In early to mid-July, PJM sends requests for adjustments to EDCs/LSEs. Responses are required in September so the results can be included in the Load Analysis Subcommittee meeting in September/October. After the results are presented, PJM reviews and modifies load forecast adjustment submissions, making additional requests for information from EDCs/LSEs as needed. In October/November, PJM announces the final large load adjustments at a Load Analysis Subcommittee meeting. PJM requires EDCs/LSEs to provide written documentation of their load forecast adjustments in November/December. In December/January, PJM publishes its load forecast in the *Long-Term Load Forecast Report*. Table 1 shows the schedule for large load forecast adjustments in 2025.

Table 1. Schedule for PJM's Large Load Adjustment Process in 2025

Responsible Party	Action	Due Dates 2025
PJM	Sends Request for Large Load Adjustments to LAS/PC	Tuesday, July 1, 2025
EDC/LSE	Sends Template and any additional supporting documentation to PJM	Friday, September 5, 2025
PJM/EDC/LSE	Communication via email/calls to request additional information/details	July - November 2025
EDC/LSE	Presents adjustment request at LAS meeting	Tuesday, September 16, 2025
PJM	Reviews decisions at LAS meeting on what large load adjustments are included in load forecast	October/November 2025
EDC/LSE	Provides PJM with written documentation to post with load report	Friday, December 19, 2025

Notes and source: This table was recreated for readability. The table is from PJM's large load request template.

The large load CIFP stakeholder process created an additional step in the large load adjustment process for review of forecast adjustments by RERRAs — public utility commissions (PUCs), municipal boards, and cooperative (co-op) boards. PJM's proposed revisions to its *Load Forecasting and Analysis* manual (Manual 19) indicate that the core adjustment process will remain unchanged, with three additions.[20] First, EDCs/LSEs must inform PJM of intent to submit requests by August 1 each year. Second, the RERRA review must occur before EDCs/LSEs submit their adjustments to PJM in September/October. Third, an independent consultant will conduct a parallel large load forecast, using a combination of EDC/LSE adjustment requests and its assessment of national trends.

RERRA review is voluntary, though EDCs/LSEs that submit adjustment requests must provide an opportunity for review. The EDC/LSE must indicate in its submission if the RERRA waived the opportunity to review. PJM does not specify a timeline for RERRA review, but the EDC/LSE must specify when the adjustment was shared with the RERRA and if the EDC/LSE and RERRA held any meetings to discuss the adjustment.

PJM does not provide specific guidance on the kinds of feedback that it expects RERRAs will provide. EDC/LSE requests must document what feedback the RERRA provided, though the EDC/LSE is not required to incorporate the feedback. EDC/LSE requests must include verification from the RERRA that EDC/LSE description of its process and feedback is accurate. PJM will disclose whether a RERRA reviewed adjustment requests but will not disclose feedback provided by the RERRA. PJM may not consider adjustment requests valid unless EDCs/LSEs document RERRA review.

[20] The information in this section is based on the proposed revisions to Appendix B of this manual that were released on May 1, 2026. PJM's proposal may change with stakeholder feedback.

2.2 Requirements for Load Forecast Adjustment Requests

PJM's proposed revisions to Manual 19 define large loads for the purposes of load adjustment as 50 MW or larger.[21] PJM does not have a required methodology for EDC/LSE large load adjustments but does set requirements for adjustment requests. Each EDC/LSE's approach to forecasting large load adjustments must be documented, made publicly available through PJM's website, and justified to PJM staff and stakeholders if necessary.

EDCs/LSEs submit large load adjustment requests through PJM's Excel-based adjustment request template. In this template, EDCs/LSEs are required to provide detailed project-specific information on project status and characteristics, in addition to expected load. This information includes:

> *"… facility owner, location, status of site control and permitting, load type (if data center, type of data center if known), project demand characteristics (includes online date, and capacity and demand over time), project configuration (network vs co-located) project stage (Electric Service Obligation or ESO, Construction Commitment or CC , or Other), and financial responsibility (including information on minimum demand provisions, length of term, exit fees, etc.)."*[22]

The actual load forecast information required in the adjustment request template includes large load annual and monthly capacity, annual and monthly peak demand, and monthly energy demand. An EDC/LSE might use a variety of approaches to calculate these values (see Appendix 1 for examples). For example, an EDC/LSE might include load with an existing electric service agreement (ESA), including specified monthly capacity and energy demand, in its forecast with limited to no modification. Similarly, an EDC/LSE might include load that has only made an interconnection request in its adjustment request but modify (discount) it and use assumptions to fill in uncertain or unknown values.

Analytically, there are four key factors that EDCs/LSEs in the PJM region use to modify or calculate large loads' requested capacity and energy demand: probability factor, utilization rate, ramp rate, and load factor. The box below describes these factors and clarifies PJM's use of the terms "capacity" and "demand" in large load forecast adjustments.

Key Concepts in Large Load Forecast Adjustments in PJM

Capacity. Capacity is the maximum capacity requested by large load customers. For instance, if a load requests 100 MW of capacity, it can consume a maximum of 100 MW.

Demand. Demand is the projected actual summer peak consumption by large loads. For instance, large load customers might request 1,000 MW of maximum capacity but only consume a maximum of 700 MW during summer peak.

[21] Adjustments for loads smaller than 50 MW may be included on a case-by-case basis.
[22] The current template requires less detailed information.

Probability factor. Probability factor is the probability of an interconnection request achieving commercial operation. For instance, if only half of interconnection requests have historically achieved commercial operation, the probability factor for interconnection requests might be 50%.

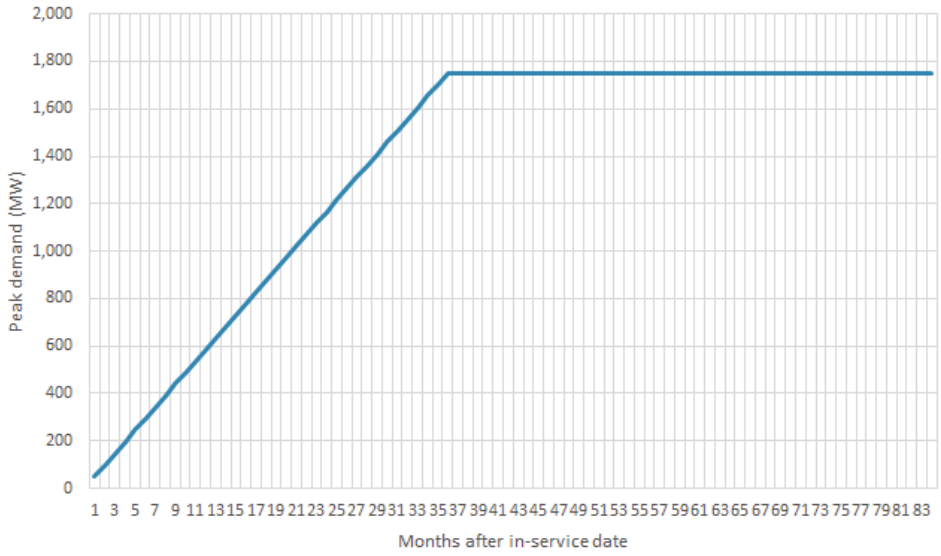
Utilization rate. Utilization rate (also utilization factor) is the ratio between demand and capacity, or the share of requested capacity that the load actually uses. If customers request 1,000 MW but only use 700 MW, the average utilization rate is 70% (= 700 MW / 1,000 MW). PJM uses a default minimum utilization rate of 70% to modify forecasts. Utilization rate and probability factor are distinct, though are sometimes confused and combined into a single factor.

Ramp rate. Ramp rate is the expected amount of time for large loads to reach their full requested capacity or demand, in months or years. For instance, in 2026 a customer may request 100 MW of new service, with an expected commercial operation date of January 2029. If the customer has a ramp rate of 36 months, the project will reach its full capacity in January 2032. Ramp rates are often assumed to be linear, which means that each month the project's capacity would increase by 2.78 MW (= 100 MW ÷ 36 months). PJM uses a default 36 month ramp rate.

Load factor. Load factor is the ratio between average and peak demand. It can be used to estimate energy demand from peak demand and vice versa. For instance, a customer with an annual load factor of 80% and an expected (actual) peak demand of 70 MW will have an average demand of 56 MWa (= 70 MW × 0.80) and an annual energy demand of 490,560 MWh/year (= 56 MW × 8,760 hours/year). Load factors can be defined over any time period but will typically be for months, seasons, or a year. Average demand is calculated by dividing energy demand by the number of hours in the time horizon. In this case 56 MW = 490,560 MWh/yr ÷ 8,760 hours/year.

Example. A utility receives large load requests for 5,000 MW of capacity. Historically, 50% of these requests have achieved commercial operation. The loads that achieve commercial operation are expected to have an average utilization rate of 70%, an average ramp rate of 36 months, and an average load factor of 80% (monthly and annual). During the first three years, expected peak demand will increase by 49 MW per month (= 5,000 MW × 0.50 × 0.70 ÷ 36 months) and will reach 1,750 MW (= 5,000 MW × 0.50 × 0.70) by year 4 (end of month 36), as shown in the figure below. Expected annual energy demand will increase by 4,088 GWh/year (= 49 MW/month × 12 months × 0.80 × 8760 hours/year × 1 GWh/1,000 MWh) and reach 12,264 GWh/year (= 1,750 MW × 0.80 × 8760 hours/year × 1 GWh/1,000 MWh) by year 4.

Figure: Large load forecast from the example



2.3 PJM Review and Modification

PJM uses a two-part process to modify load adjustments. In the first part ("part 1"), PJM determines whether requested adjustments may have already been captured in its load forecast model and, if so, removes them from the request. Manual 19 does not specify how PJM makes these determinations.[23]

In the second part, PJM reviews remaining adjustment requests and modifies them based on interconnection status, performance characteristics, and industry trends. Going forward, the second part of PJM's process will also rely on a review by a third-party consultant (see Section 2.4). Adjustment requests with in-service dates that are within three years of the initial forecast year – the time horizon used for the RPM – must have an electric service obligation (ESO), a construction commitment (CC), or a long-term supply commitment plus a financial commitment (Other) to be considered "firm" and included in the load forecast (see box). PJM also appears to consider requests that have an ESO/CC but have in-service dates longer than three years from the forecast year as firm and eligible to be included in the forecast.[24] PJM may still derate firm requests, as described below. PJM categorizes adjustment requests with expected three- to eight-year in-service dates that do not have an ESO/CC as "Other" (see box), and requires supporting documentation on project milestones and probability factors to include these loads in the forecast as non-firm demand.[25] If EDCs/LSEs do not provide a probability

[23] In other documents, PJM notes that it "reviews economic forecast to determine if load shift is captured" and "obtains hourly load history to isolate impact and avoid double counting" (see *Load Forecast Development & Use in PJM*). However, as described in subsequent text, in practice it appears as if PJM assumed that all non-data center industrial adjustments were already included in the base load forecast. It also appears that PJM removes data center load from its regressions in calculating the base load forecast, to avoid double counting.

[24] The *Load Adjustment Request Implementation* document states that, "For identified projects coming online in more than three years but less than eight years, arrangements without construction commitments will be considered for inclusion in the PJM forecast" (p. 4), implying that arrangements with a construction commitment would be included in the forecast.

[25] The information in this paragraph is based on the *Load Adjustment Request Implementation* document. However, the timelines and approach to non-firm load in this document were not included in the proposed revisions to Manual 19.

factor, PJM derates these requests by a default probability factor of 50%. EDCs/LSEs can include additional load requests after eight years, based on trends, but are required to justify these inclusions to PJM.

Definitions of Electric Service Obligation (ESO), Construction Commitment (CC), and Other

ESO — "The ESO reflects a binding commitment by a prospective retail customer to construct and operate facilities that will use electric services provided by the electric service provider in accordance with the forecast load. That customer obligation may be reflected in different forms, including but not limited to a contract between the customer and the EDC/LSE or in rates, terms, and conditions of service approved by a Relevant Electric Retail Regulatory Authority (RERRA) that control [sic] the relationship between an electric service provider and an end-use retail customer. The ESO should reflect a commitment to pay the charges associated with the requested load and can also outline the scope of work, fees, termination, and other relevant information."

CC — "A CC is a legal obligation that a public utility must discharge in furtherance of its obligation to serve all load and involves constructing system facilities necessary to serve both load being added by an end-use customer as well as existing load in a manner that continues to ensure safe, adequate and reliable service to all customers. A construction commitment must provide indication that corresponding facilities are either in the process of being constructed or are in the public utility's capital project plan and that the customer has made a contribution in aid of construction (CIAC). It may describe what will be done, how it will be executed, and if there is any associated payment by an end-use customer."

Other — "Other would include projects that have cleared demonstrable project milestones may include site control, financial commitments, officer certification, long-lead procurement, or state support for the anticipated load growth and associated transmission upgrades. If Other, submitter will be required to provide details."

Source: Definitions are from proposed revisions to Manual 19, p. 27.

PJM's modifications of large load adjustment requests in its 2026 load forecast illustrate its approach. For part 1, PJM removed all non-data center industrial load from adjustment requests due to "overlap with economic variables."

For part 2, PJM used a three-step process to modify remaining data center load forecasts.

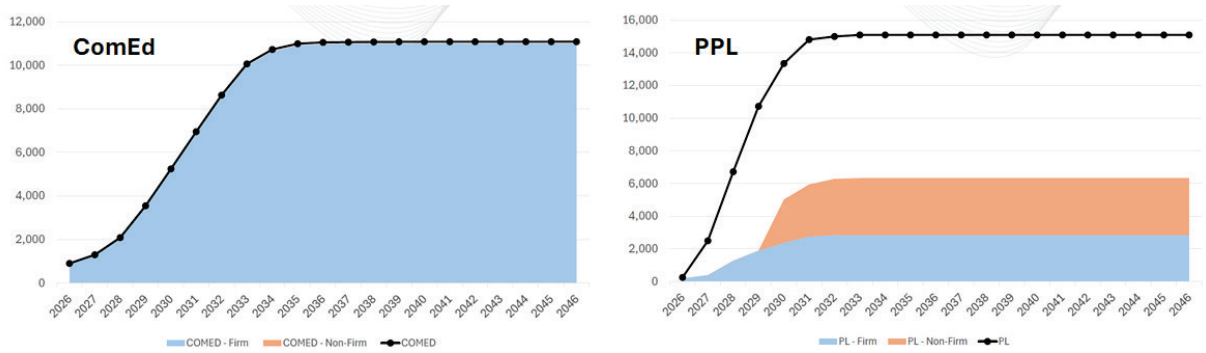
1) Step 1 – Categorize projects into firm and non-firm, based on whether the EDC/LSE reported that the project has an ESO/CC (firm) or is in an earlier phase of interconnection (non-firm).
2) Step 2 – Zero out non-firm projects before 2030 (within 3 years) and derate non-firm projects by 50%.

3) Step 3 – Apply a utilization rate of 70% and a minimum ramp rate of 36 months or use EDC/CC utilization and ramp rates if explicitly reported; make additional modifications to non-firm requests based on "national constraints."[26]

This process led to very different modifications for EDC/LSE requests. For instance, PJM accepted nearly all of ComEd's adjustment requests (left panel of Figure 4). Exelon's documentation of its adjustment methods reported that all data center load included in the request had an engineering agreement and financial deposits, and that Exelon used a utilization rate of 70% and 5-8-year ramp rates to derate its requests (see Appendix 2).[27]

By contrast, PJM modified PPL's requests down by more than 80% from 2026-2029 and 65% from 2030 to 2046. PPL included data center load with either an electric service agreement or a letter of authorization (LOA) for interconnection study and did not specify utilization rates or ramp rates. PJM discounted LOA (non-firm) requests by 50% and imposed 70% utilization rates and 36-month ramp rates on all of PPL's data center adjustment requests.

Figure 3. PJM's Modifications to ComEd and PPL's Adjustment Requests, 2026 Load Forecast



Source: Figures are from PJM, *Load Adjustment Requests Summary for 2026 Load Forecast – Preliminary*.

To our knowledge, PJM did not corroborate the reported agreements, utilization rates, or ramp rates submitted by EDC/LSE templates and it is not clear that PJM's modifications were based on comparable metrics (see Appendix 2). For instance, EDCs/LSEs may have different (similar) names for the same (different) kinds of agreements, with varying levels of financial commitment required at each stage of the load interconnection process. Appendix 1 discusses agreements, milestones, and financial commitments in load interconnection. Appendix 2 reviews EDC/LSE load forecast adjustment documentation and terminology in the 2026 load forecast.

PJM's proposed revisions to Manual 19 state that requests that are categorized as non-firm are not included in the load used to clear PJM's capacity market. However, PJM does not clarify, either in Manual 19 or in its *Transmission Expansion and Planning* manual (Manual 14b), how non-firm requests are considered in transmission planning. PJM's treatment of non-firm requests effectively assumes that, for the purposes of

[26] PJM's *Load Adjustment Requests Summary for 2026 Load Forecast – Preliminary* mentions this modification ("national average scaling") but does not describe specific methods.
[27] Exelon is the parent company of ComEd. Exelon provided documentation on behalf of all its operating companies.

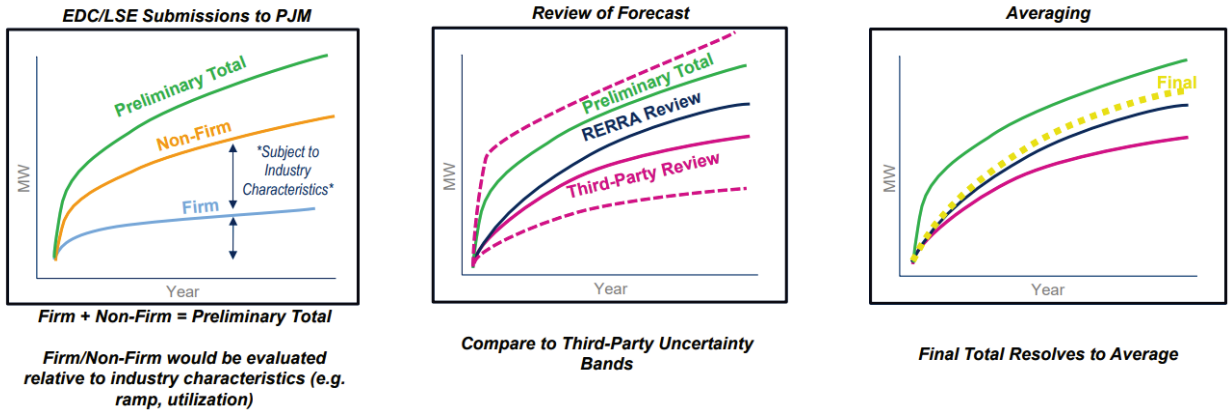
capacity market procurement, data center projects cannot progress from an interconnection request to in-service in less than three years.[28]

2.4 Consultant Review

PJM's proposed Manual 19 revisions suggest that it "may obtain additional review and an independent forecast through an independent third party," though in its June 5 presentation on the revisions it appears as if the third-party review will play a significant role in the forecasting process.[29] The presentation describes two ways in which PJM can use the review: (1) validation of PJM's large load adjustment, including additional communication with EDCs/LSEs; (2) incorporation of regional and national trends in electricity demand, providing an independent assessment of the national constraints modification of non-firm requests in step 3 of PJM's process.

PJM will use the EDC/LSE submissions, post-RERRA review forecasts, and the third-party forecasts to develop an averaged final forecast. Averaging depends on whether the submissions is within, exceeds, or is below the third-party forecast (Figure 5), but the presentation does not specify how the averaging will be done.

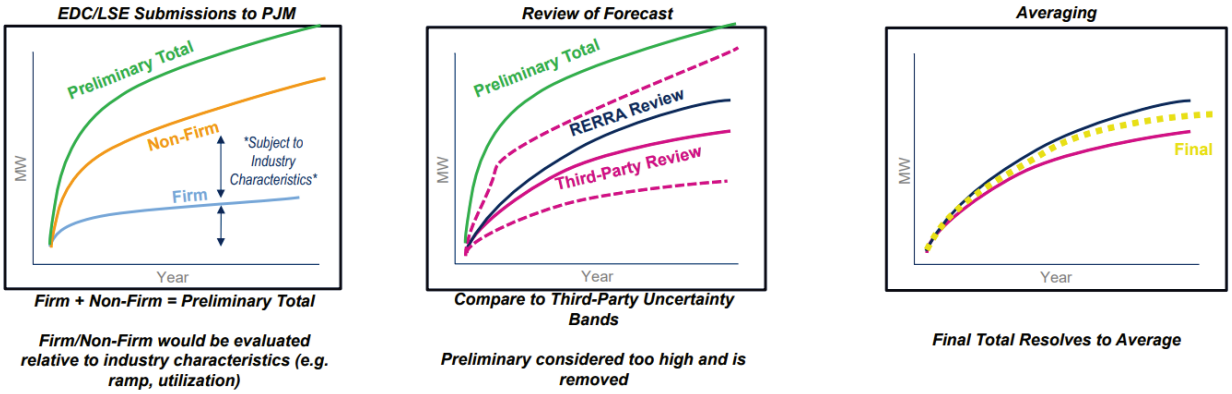
Figure 4. Proposed Use of Third-Party Review in Forecast Adjustments
Scenario 1: EDC/LSE submission is within uncertainty bands



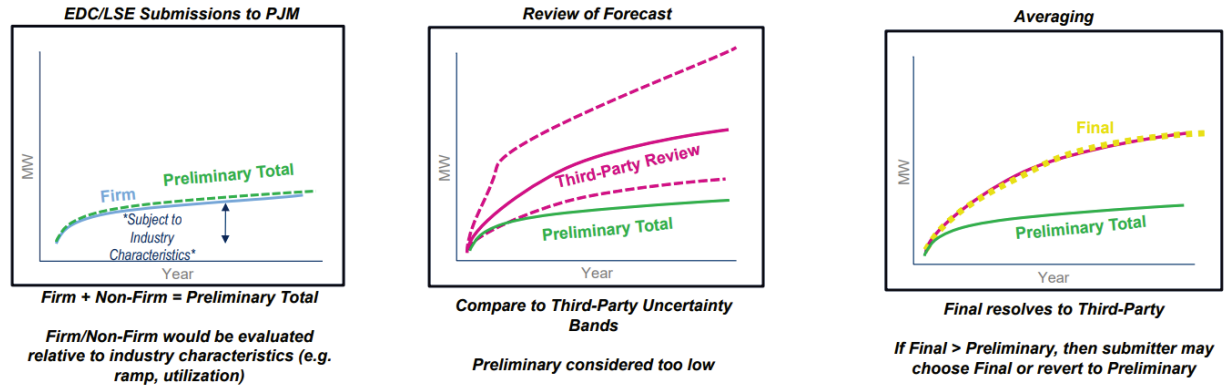
[28] Ideally, a data center request would be included in the load forecast used three years before it begins service, to ensure that adequate generation capacity can be made available through PJM's three-year forward capacity market. However, if a data center submits an interconnection request in 2026 and signs a construction agreement in mid-2027, it would not be included in PJM's load forecast until the 2028 forecast year. The 2028 load forecast corresponds to the 2031/2032 auction year.

[29] The information in this sub-section are based on a June 5, 2026 Load Analysis Subcommittee presentation on *Manual 19 – Attachment B: Load Forecast Adjustment Guidelines*.

Scenario 2: EDC/LSE submission exceeds uncertainty bands



Scenario 3: EDC/LSE submission is below uncertainty bands



3. Large Load Forecasting and RERRA Participation in Other ISO/RTO Regions

This section provides an overview of large load forecasting and how state agencies participate in forecasting in other ISO/RTO regions. Differences between large load forecasting processes in these states and PJM also involve differences in the design of resource adequacy mechanisms and in transmission planning practices.

Table 2 summarizes, for each ISO region, which entity is responsible for the base load forecast and large load forecast, and how preliminary large load forecasts are modified to arrive at a final load forecast. The seven ISO regions can be grouped into four categories: (1) state agency load forecasting (CAISO), (2) EDC/LSE base and large load forecasting (MISO, SPP), (3) ISO base load forecasting and EDC/LSE large load forecasting (ERCOT, PJM), and (4) ISO base and large load forecasting (NYISO).

Table 2. Responsibility for Base and Large Load Forecasts and Large Load Forecast Modification by ISO Region

ISO Region	Load Forecast Responsibility		Large load forecast Modifications
	Base	Large load	
CAISO	State agency	State agency	State agency develops large load forecast based on utility interconnection data
ERCOT	ISO	Transmission service providers	State law only allows large loads with an ESA to be included in the load forecast; ERCOT further modifies large load forecasts based on historical data
ISO-NE	ISO	Transmission owners	ISO-NE modifies using project-specific derate factors
MISO	LSEs/EDCs	LSEs/EDCs	No modification
NYISO	ISO	ISO	NYISO develops large load forecast based on interconnection data
PJM	ISO	EDCs/LSEs	PJM modifies forecasts based on information provided by EDCs/LSEs
SPP	EDCs/LSEs	EDCs/LSEs	No modification

Sources: This table is largely based on the ISO/RTOs' responses ("Rosner letter responses") to FERC Chair David Rosner's "Letter to the RTOs/ISOs on Large Load Forecasting" and other sources described later in the text.

CAISO. In California, a state agency – the California Energy Commission (CEC) – generates the base and large load forecasts used in the state's resource adequacy program and in CAISO transmission planning. The CEC collects information on large load projects from utilities and groups them into three categories: (1) projects that have an electric service agreement; (2) projects that have a formal interconnection request but have not yet completed interconnection studies; and (3) inquiries.

The CEC uses confidence levels (probability factors) to de-rate projects within each group for low, mid, and high forecast scenarios: low, mid, and high (Table 3). In 2025, it calculated the large load to be included in load forecasts by multiplying a project's requested capacity by the confidence level, a utilization factor (67%), and a default ramp rate (7 years) if project-specific ramp rates are not available.[30] The mid scenarios are used in planning for system-wide resource adequacy and transmission needs, whereas the high scenarios are used in planning for local needs.[31]

Table 3. The CEC's Confidence Levels (Probability Factors) by Large Load Group for Low, Mid, and High Forecast Scenarios, 2025 Load Forecast

Large Load Group	Low Scenario	Mid Scenario	High Scenario
Group 1. ESAs	50%	70%	100%
Group 2. Interconnection requests	-	33%	50%
Group 3. Inquiries	-	-	10%

[30] CEC, *2025 IEPR: Preliminary Data Center Forecast*, slide 9.
[31] See slide 28 of the CEC's *2025 IEPR Forecast - Updated Results* for more on how these scenarios are used.

Example of the CEC's Approach

A 100-MW data center has paid a study deposit and formally requested interconnection studies and an in-service date of 2030 but does not yet have an ESA and did not provide expected ramp data to the utility. For the 2030 load forecast, the CEC would count 3 MW (= 100 MW × 33% × 67% × 1/7) from the project's 100-MW request toward the load forecast used in system planning and 5MW (= 100 MW × 50% × 67% × 1/7) toward the load forecast used in local planning. For each year the CEC would increase the project's mid and high scenario load forecast by approximately 3 and 5 MW, respectively. In 2037, the year that the project reaches its full capacity, its mid and high forecast would be 22 and 34 MW and would continue at those levels until the final year of the CEC's 20-year forecast.

ERCOT. ERCOT conducts a base load forecast and relies on transmission utilities (transmission service providers or TSPs) for large load forecasts. For its 2025 long-term load forecast, ERCOT requested two kinds of information from TSPs: (1) large load contracts (ESAs) and (2) official letters, which are large load requests without an ESA but with a supporting attestation letter from a TSP.[32] TSPs provided requested capacity and ramp rates for each customer.

ERCOT made two adjustments to these data. First, it assumed a 180-day delay for all projects, in addition to ramp rates, based on historical data. Second, it multiplied all projects' capacity by a utilization rate of 49.8%, based on data from 2022 through 2024. Third, it multiplied offer letter capacity by a probability factor of 55.4%, based on the number of prior projects with offer letters that began operation in 2024.
Recent state rules – *Substantive Rules Applicable to Electric Service Providers* (§25.370 ERCOT Large Load Forecasting Criteria) – that took effect in 2026 require that any large load (≥ 75 MW) included in load forecasts used for transmission planning or resource adequacy assessments must have a completed interconnection agreement. ERCOT had not yet completed its *2026 Long-Term Load Forecast* report at the time of writing.[33]

MISO and SPP. In MISO and SPP, utilities are responsible for both base and large load forecasts. MISO does not verify or modify EDC/LSE-provided large load forecasts used in its resource adequacy construct and in nearer-term transmission planning. However, MISO also conducts its own 20-year load forecast that it uses for longer-term transmission planning. For this forecast, MISO uses publicly and commercially available data on data center development, applying a combined probability and utilization factor of 50% and a 5-year ramp rate.[34]

Like MISO, SPP does not verify the load forecasts provided by LSEs, but with different implications because of differences in resource adequacy mechanisms and transmission planning. SPP's resource adequacy construct is LSE-specific rather than regional, which isolates the impact of large load forecasts in resource adequacy

[32] Unless otherwise specified, the information in this section is from ERCOT's 2025 *Long-Term Hourly Peak Demand and Energy Forecast*, available at https://www.ercot.com/gridinfo/load/forecast.
[33] In April 2026, ERCOT filed its preliminary long-term load forecast with the Texas PUC (PUCT). In its cover letter to the PUCT, ERCOT requested a further downward adjustment of its 2026 summer peak forecast, from 112,000 MW to 90,500-98,000 MW based on historical data.
[34] See MISO's Rosner letter response for more detail.

procurement.[35] SPP can also reject transmission service requests for new loads, if SPP determines that the LSE does not have adequate resources to serve the load.[36] Base load forecasts submitted by LSEs for SPP's Integrated Transmission Plan (ITP) must have transmission service to be included in SPP's load forecast. However, in 2025 SPP began to include "spot" loads – loads "that are anticipated, but that do not have transmission service" – in a scenario (Future 2) in its ITP.[37] In its 2025 and 2026 plans, SPP did not modify spot load submissions from LSEs, though spot load additions are subject to stakeholder review.[38]

ISO-NE. ISO-NE includes a forecast of large loads in its 2026 forecast, though to date the region has had limited large load growth. ISO-NE's forecast process has four steps: (1) collect information on large load (≥ 20 MW) projects that have a formal study agreement, (2) develop "effective nameplate" values for each project, (3) develop 20-year nameplate forecasts for each project, and (4) develop hourly profiles for each project based on load type.[39]

In the second step, ISO-NE derates projects' requested capacity, as reported in the transmission owner surveys, to arrive at effective nameplate capacity values. ISO-NE's derate factors are based on achieved milestones, a discretionary confounding factors term, and a fixed 70% capacity utilization factor (Table 4). For instance, a large load project with a reported 100 MW capacity that has completed an interconnection study (70% derate) and has frequently changed its requested capacity (90% confounding factors derate) will have an effective nameplate capacity of 44 MW (= 100 MW × 0.70 × 0.90 × 0.70).

Table 4. ISO-NE's Derate Factors for Large Loads' Requested Capacity

General Milestone Derate Factors	
Entered into study agreement	60%
Interconnection study completed	70%
Construction agreement	80%
Achieved commercial operation	90%
Other Derate Factors	
Confounding factors derate factor	90%
Capacity utilization derate factor	70%

NYISO. NYISO is somewhat unique among ISOs in that it has historically overseen a formal load interconnection process.[40] This gives NYISO direct access to information on large load customers rather than having this

[35] SPP sets resource adequacy requirements for each LSE based on the LSE's non-coincident peak load forecast plus an SPP-determined planning reserve margin. SPP verifies that LSEs have enough unforced capacity to meet their requirement and enforces penalties on LSEs that do not.
[36] To obtain transmission service for new loads, customers must request service (delivery point additions) and provide a 10-year load forecast. SPP reviews requests to determine if the LSE has enough designated resources to serve the load and, if not, can reject the request. For a more detailed description, see SPP's Rosner letter response and Attachment AQ of the SPP tariff.
[37] SPP's Rosner letter response, p. 3. See also SPP's 2025 *Integrated Transmission Planning Assessment Report*, pp. 94-97.
[38] *Ibid.*
[39] See ISO-NE Load Forecast Committee's *Final Draft 2026 Large Load Forecast* for a more detailed description of these steps and the information in this section.
[40] ERCOT implemented a formal load interconnection process in 2025, but before that NYISO was the only ISO that oversaw a load interconnection process.

information provided by utilities. NYISO reports that it considers several factors in deciding whether to include load interconnection requests in its load forecasts but appears to do so on a case-by-case discretionary basis.[41]

4. Considerations for RERRA Participation in PJM's Load Forecast Adjustment Process

RERRA participation in PJM's proposed load forecast adjustment process involves review of EDC/LSE adjustment requests, but may also involve regional coordination among RERRAs and requesting clarifications, asking questions, and providing feedback to PJM on its modification methods. This section is organized into these three areas: (1) RERRA review of EDC/LSE adjustment requests, (2) regional coordination, and (3) potential clarifications, questions, and feedback to PJM. A central theme explored in the RERRA review section (section 4.1) is how to identify an appropriate level of effort in RERRA reviews, to ensure the RERRA is meeting its oversight responsibilities but avoiding duplication of PJM's efforts. Some amount of EDC/LSE reporting and RERRA verification may help increase transparency and accountability.

4.1 RERRA Review of EDC/LSE Adjustment Requests

PJM has not specified the type of load forecast adjustment review or feedback it is seeking from RERRAs. RERRA review could range from none or relatively minimal to extensive and staff-intensive. RERRAs can consider three questions to help determine the desired level of effort along this spectrum.

Question 1. What information is PJM already collecting and verifying from EDCs/LSEs and what information does PJM ultimately need?

PJM plans to collect most of the information it needs to verify and modify large load adjustment requests from EDCs/LSEs in its large load request template and additional requests for information, though PJM recognizes that RERRA rules may limit what information EDCs/LSEs can share with PJM.[42] PJM's proposed approach does not appear to request that EDCs/LSEs share individual contracts. It is not clear how much effort PJM will expend to verify contracts and any parameters (utilization rates, ramp rates) provided by EDCs/LSEs.

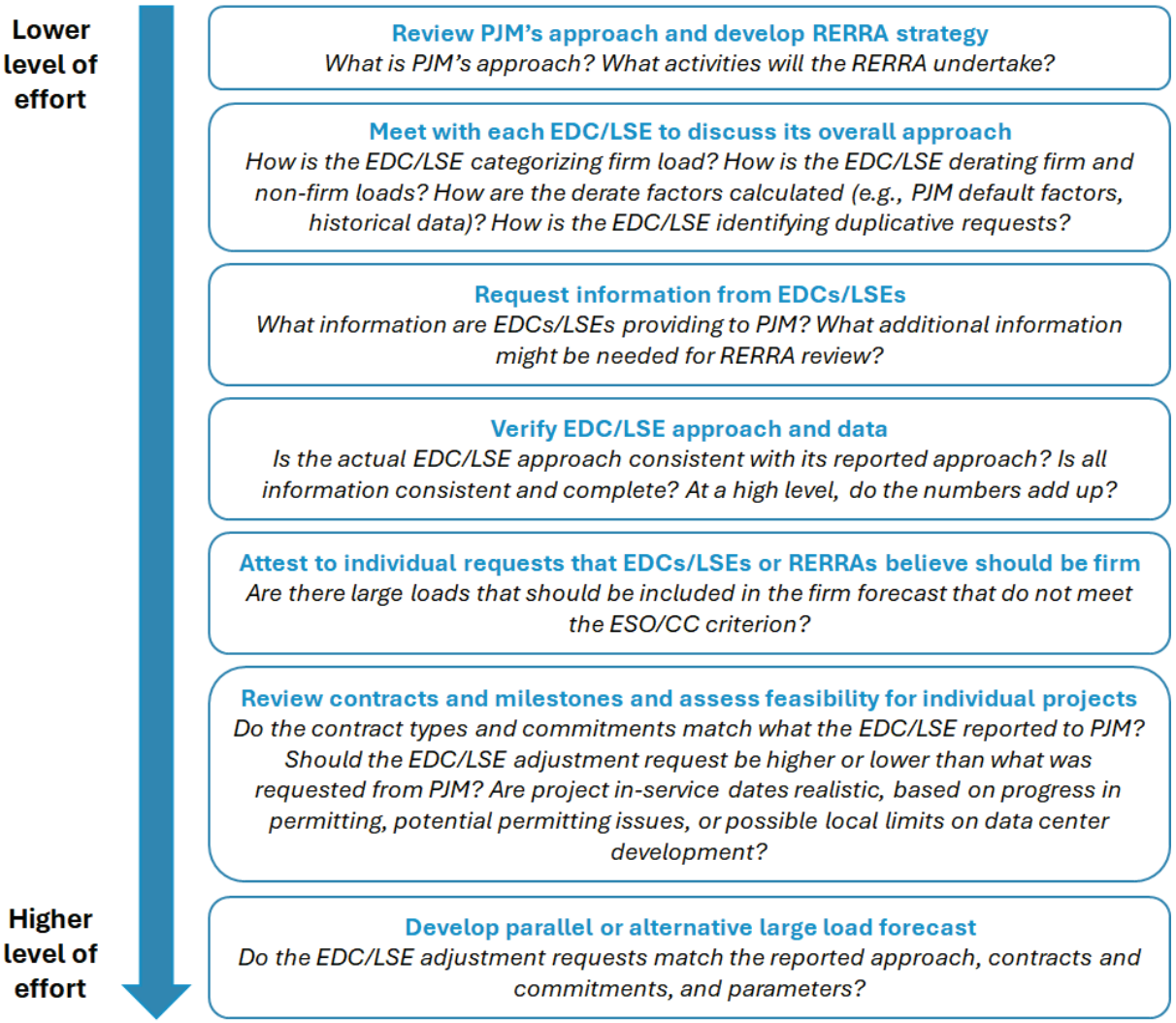
Ultimately, PJM needs three kinds of information from EDCs/LSEs: (1) information to assess duplicative requests and duplication within its baseline forecast (e.g., facility name, type, size, and whether it has similar request elsewhere in PJM);[43] (2) information to assess the certainty of adjustment requests and determine firm/non-firm status and, for non-firm, probability factors (e.g., project milestones); (3) information to derate requested capacity and convert capacity to energy (e.g., utilization rates, ramp rates, load factors).

Question 2. What will RERRA review entail and what will the final feedback product look like (bearing in mind staff and other resource constraints)?

[41] See NYISO's Rosner letter response.
[42] The proposed Manual 19 revisions require that, "Submitters must ensure any customer nondisclosure agreement (or equivalent agreement) include ability to share all relevant information with PJM related to large loads (existing or planned)," while acknowledging that "state law prohibit sharing all or some [additional] information with PJM" may limit what can be shared. See Section 2.2 for a list of information PJM will collect from EDCs/LSEs.
[43] Duplicative requests refers to multiple requests for the same project. Duplication in the load forecast refers to when a large load is included both in the base forecast and in the forecast adjustment.

RERRA review might include a mix of activities with different levels of effort (Figure 6). The level of effort that is appropriate will depend on the RERRA's desire, capability, and staff capacity to verify the information EDCs/LSEs provide to PJM, validate the forecast, attest to the likelihood that adjustment requests will come online, or create an alternative forecast. In Figure 6, the first four activities involve more passive review, while the final three activities involve more active engagement, review, and analysis.

Figure 5. Potential RERRA Activities and Questions that the Activity Addresses



In the sixth activity, RERRAs may play a role in verifying the feasibility of individual project in-service dates, based on permitting status, permitting challenges, or potential limits on data center and other large load development. To understand potential permitting issues and development limits, RERRAs might need to consult with other state agencies, such as air and water agencies. These consultations might involve confidentiality issues that would need to be addressed in advance. Another approach to capturing permitting constraints might be to use an average delay factor in de-rating adjustment requests. It is unclear which approach – individual facility or zonal average delays – would be more useful and accurate from PJM's perspective.

Under the proposed Manual 19 revisions, RERRAs are not obligated to provide any verbal or written feedback to the EDC/LSE, even if they review the adjustment request. If RERRAs do provide feedback, it could be less formal (e.g., through a meeting or an email) or more formal (e.g., a written document) but will likely be shaped by communication protocols. RERRAs might also involve other agencies and stakeholders, such as permitting agencies and consumer advocates, in their review process. Given PJM's proposed timelines for the 2026 adjustment request cycle, it may be challenging for RERRAs to conduct structured public meetings or formally request information from EDC/LSEs.

Question 3. How will or could RERRA feedback link with other processes, such as resource planning, utility large load reporting requirements, and large load registries?

Several of the activities in Table 5 overlap with existing processes, including:

- *Resource planning*. Load forecasting is an integral part of resource planning and distribution system planning. In aggregate, the information that PJM is requesting from EDCs/LSEs would likely also be developed and made public through a resource planning proceeding. RERRAs could consider how to incorporate reviews of large load interconnections in proceedings related to resource and distribution system planning.
- *State reporting requirements*. *S*everal states have requirements for regular EDC/LSE reporting on large loads, including Arkansas, North Carolina, and Georgia.[44] Other states have legislation authorizing and requiring PUC oversight and reporting on large load forecasts. These include Pennsylvania's HB1924 and New Jersey's Bill S4938/S3370. These reporting requirements may overlap with the large load adjustment process and the information that PJM is requesting from EDCs/LSEs.
- *Large load registries and databases*. Some states have laws, regulations, or initiatives to develop large load registries or databases, which may contain most if not all of the information EDCs/LSEs use to develop their adjustment requests. For instance, Maryland's HB1532 will require the Maryland Publish Service Commission to develop a large load customer registry by July 1, 2027.

Aligning RERRA review with these activities may help to avoid duplicative effort, though it may be challenging to do so in the 2026 cycle due to time constraints. RERRAs could consider providing feedback to PJM on the timing of LLA and the expectations for RERRA review to better align PJM's forecasting with relevant state proceedings.

4.2 Regional Coordination

Given that the impacts of large load forecast error are of regional concern, there may be areas of common interest among states that would support regional coordination on large load adjustments, including:

- *Coordination on review methods*. Discuss RERRA approaches to review (less effort) or agreement on consistency for some or all of RERRA review approaches (more effort).

[44] These include reporting requirements for Entergy Arkansas on its Large Power High Load Density Service, semiannual reporting reuquirements on large loads for Duke (North Carolina), and quarterly reporting requirements for Georgia Power.

- *Common understanding*. Develop a common understanding of PJM's approach and methods, EDC/LSE terminology and practices around large load interconnection, and EDC/LSE methods for large load forecasting and adjustment requests.
- *Agreement on minimum thresholds*. Agree on a minimum level of financial commitment (e.g., agreement, payments) required for large loads to be categorized as firm, and included in load forecasts.
- *Information sharing*. Identify and implement mechanisms to share information on large load forecasts, ranging from common reporting standards for EDCs/LSEs to a regional large load registry.
- *Joint questions or feedback to PJM*. Submit coordinated clarifications, questions, and feedback to PJM on large load adjustments.

An expanded group of the Organization of PJM States, Inc. (OPSI) Load Forecast Working Group might provide a forum for discussion and action on these elements. Given that around 20% of PJM's large load adjustment is for co-ops, it may also be important to broaden the discussion to include non-PUC RERRAs.

4.3 Potential Clarifications, Questions, and Feedback for PJM

Based on this memo, nearer-term clarification, questions, and feedback for PJM might include:

- *Financial commitment and firmness*. Does PJM have a minimum level of financial commitment from customers that would be required to be included in the firm forecast, or is any commitment acceptable? Does the customer need to have provided initial collateral or payment?
- *Modification parameters*. Is PJM planning to make its default probability factors, utilization rates, ramp rates, and load factors more empirical over time? If so, how? Is there a minimum amount of data that PJM will require that EDCs/LSEs have to use their own parameters? Would it be worthwhile to add a delay parameter that accounts for average delays in connecting projects, similar to ERCOT's (18-month) parameter?
- *Use of adjustment requests*. How is PJM planning to use the non-firm forecasts in transmission planning and is PJM planning to report on how it has used RERRA review?

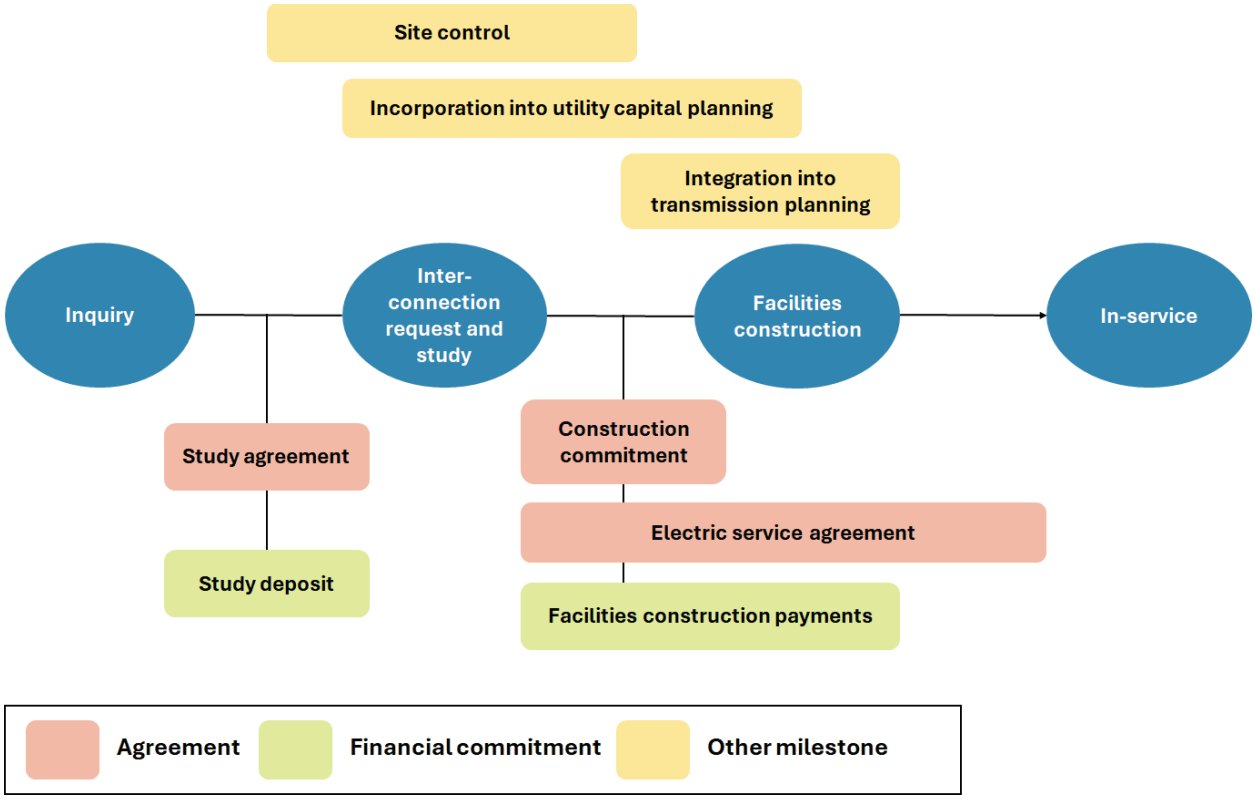
Clarifications, questions, and feedback will change as PJM's load adjustment process continues to evolve.

Appendix 1: Milestones, Agreements, and Commitments

PJM's approach to modifying large load forecast adjustments relies on an assessment of completed milestones, agreements, and financial commitments in the load interconnection process. In PJM, this process is managed by transmission and distribution utilities.

Generally, the load interconnection process begins with a non-committal inquiry (Figure A-1). In the second step, the customer submits a formal interconnection request and the utility studies the request to determine the infrastructure needed to reliably connect the customer's load. Some utilities require the customer to sign an agreement, and most utilities require a study deposit, before commencing interconnection studies. Some utilities require increasing levels of financial commitment throughout the load interconnection study process.

Figure A-1. General Description of Steps, Milestones, Agreements, and Commitments in Load Interconnection



Once interconnection studies are complete, the customer must decide whether to continue with the project. If the customer decides to continue, some utilities require the customer to commit to fund interconnection facilities and any needed transmission or distribution infrastructure. Some utilities also require customers to sign an electric service agreement (ESA) at this stage, specifying longer-term commitments. In PJM, once the customer has committed to the project there is also an additional step in which utilities must submit any transmission projects related to the customer's request in the M-3 process ("integration into transmission planning" in figure A-1).

The two points at which customers generally sign agreements and make payments are before interconnection studies begin and before work begins on any new infrastructure needed for the customer. PJM's ESO/CC requirement targets the latter stage, in which the customer has made financially binding commitments to fund the grid infrastructure needed for its project.

As described in Appendix 2, EDCs/LSEs in PJM have different terminology for the agreements and financial commitments at each stage of the load interconnection process, making it somewhat difficult to compare them.

Appendix 2: Review of EDC/LSE Documentation for Large Load Adjustment Methods

In its 2026 load forecast cycle, PJM received documentation on large load adjustment methods from 12 utilities, including a mix of vertically integrated utilities, restructured utilities, utility holding companies (Exelon, AEP), generation and transmission providers (ODEC), and co-operative utilities (NOVEC, REC, SMECO). In some cases – for instance, AEP and Exelon – the requesting utility was a holding company that developed a single approach for multiple operating companies that provide service in different states.

Table A2-1 shows the criteria that each utility used for including large loads in its adjustment requests, the terminology with which each utility described agreements and financial requirements (in the criteria column), and the assumptions that utilities used to modify their requests. It also illustrates the diversity of and lack of consistency in utility methods.[45] Some utilities included all loads with an interconnection request, whereas other utilities only included loads with an ESA. Dominion, which has the most data center load among PJM utilities, uses a more sophisticated statistical model to determine which loads will be included in its adjustment request.

Table A2-1 also hints at the differences in terminology and requirements among utilities. For instance, Exelon describes its engineering agreement as "a signed contract to begin planning and technical review including ordering of long lead materials" with "financial deposits," but it is unclear how different this is than PPL's letter of authorization, which precedes a construction services agreement but has withdrawal penalties.

Table A2-1. Utility Criteria and Assumptions for Including Large Loads in Adjustment Requests

Utility	Criteria for Inclusion	Assumptions
AEP	- For first five years of forecast, includes all customers that have a letter of agreement and at least an ESA in progress - After first five years, includes 85% of load that has requested an interconnection study and paid a study fee[46]	- Customer-specific ramp rates for customers with a letter of agreement or ESA; ramp rates for customers with completed studies not specified[47] - Methodology describes 80-95% load factors for data centers and 60% for industrial customers but unclear whether these were used in calculating energy demand
AES Ohio	- Includes all customers with an ESA, nearly all customers with a construction service agreement (CSA), some customers with a study memorandum of understanding (MOU); excludes loads with a study request without supporting agreements - Does not describe methods for how these loads are included	- Unspecified; effective 70% utilization rate based on the ratio between requested demand and capacity
Duquesne Light	- Includes customers that have completed interconnection studies and been presented in M-3 review	- Not described in documentation

[45] PJM appears to have provided template questions but only a few utilities directly responded to them.
[46] PJM noted (slide 14) that it "found it [non-firm aggregate total] to be de -rated by more than 50% from the volume of requests that AEP is receiving," which is inconsistent with AEP's methodology.
[47] "Load ramps were estimated to begin in 2031 and gradually increased through 2035."

Dominion	- Uses statistical model to develop its large load forecast	- Parameter assumptions embedded in statistical model
Exelon	- Includes customers with an engineering agreement, financial deposits, and submitted or soon to be submitted through M-3 process	- 70% average utilization rate - 5-8-year average ramp rate
FirstEnergy (FE)	- Includes all customers with an executed construction service agreement or line extension agreement	- 90% load factor for data centers, 75% load factor for industrial, 40% load factor for stadiums - Other assumptions not described
Northern Virginia Electric Cooperative (NOVEC)	- Includes all "viable projects" and 50% of "moderate risk projects"; classification based on judgement	- Statistical model, unspecified[48]
Old Dominion Electric Cooperative (ODEC)	- Includes customers with an ESA or CC	- 90% load factor - 74% utilization rate (demand ratio) - Minimum 3-year ramp rate (ramp schedule)
PPL Electric Utilities	- Includes all projects with a signed letter of authorization	- Customer-specific ramp rates - 80% utilization rate
Public Service Electric and Gas (PSEG)	- Criteria based on milestones and other factors but not specified	- Approximately 75% utilization rate
Rappahannock Electric Cooperative (REC)	- Includes projects with construction development agreements (firm) and 50% of projects with engineering letters of authorization (non-firm)	- Customer-specific ramp rates - Unspecified ramp rates and utilization rates
Southern Maryland Electric Cooperative (SMECO)	- Includes projects with study agreements	- 70% utilization rate - 5-year ramp rate

Source: EDC/LSE forecast adjustment documentation.

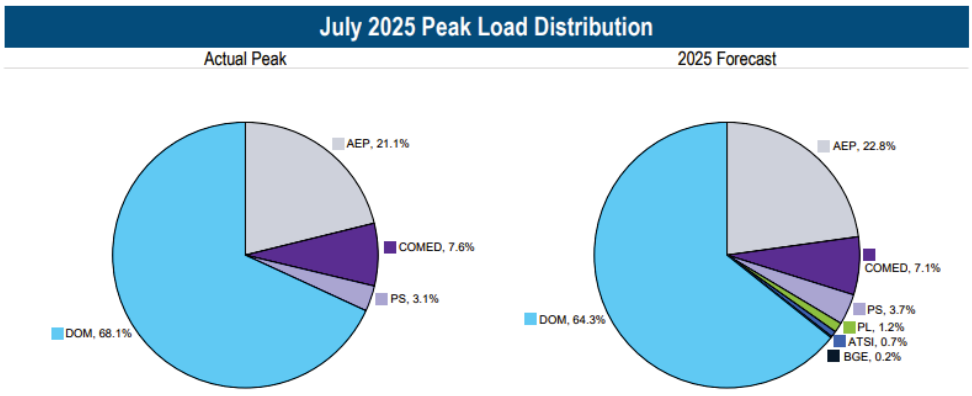
[48] PJM noted (slide 24) that "NOVEC uses average 4 year ramp rate and ~70% utilization rate for data center requested capacity."

Appendix 3. Large Load Forecast Accuracy

In May 2026, PJM published a *Load Forecast Accuracy* report that compares large load adjustments to actual historical data on large loads, with historical data provided by EDCs/LSEs. The report provides an additional layer of transparency and accountability. It contains three main items:

(1) A comparison of PJM's 2025 large load adjustment (peak demand forecast) with actual peak demand. As discussed previously, it is not clear whether PJM weather normalizes either the large load peak demand forecast or the actual peak demand data.

Figure A3-1 PJM 2025 Large Load Forecast Adjustment



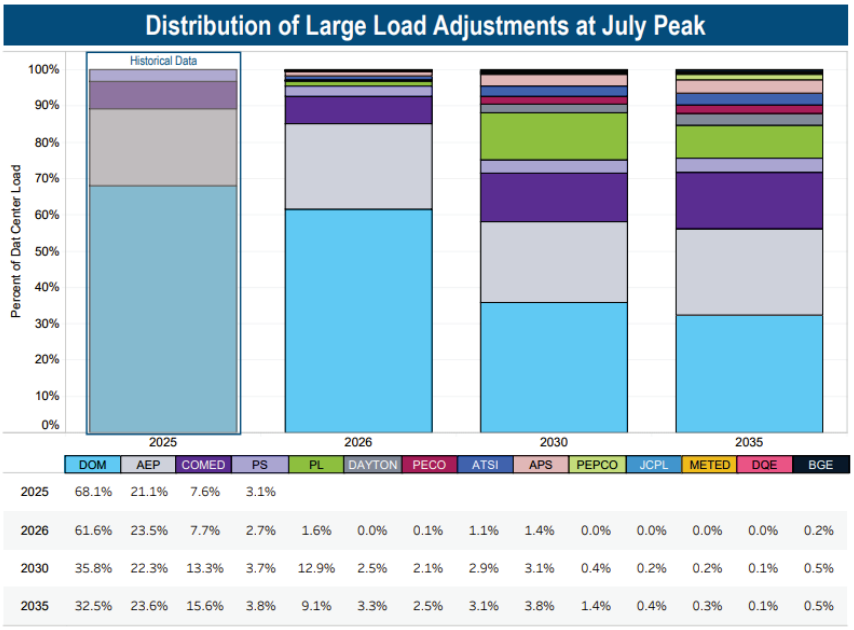
Load Per Zone (MW)

	AEP	APS	ATSI	BGE	COMED	DAYTON	DOM	DQE	JCPL	METED	PECO	PEPCO	PL	PS
Actual Peak	1,726	0	0	*	623	0	5,563	0	0	0	0	0	0	255
2025 Forecast	1,761	8	56	12	546	0	4,970	0	0	0	0	0	93	289

* This data is not shown due to being attributable to a single large load customer.

(2) Forecasted and actual shares ("distribution") of 2025 large load peak demand, and forecasted 2030 and 2035 shares. Shares are important because they impact cost allocation (Figure A3-2)

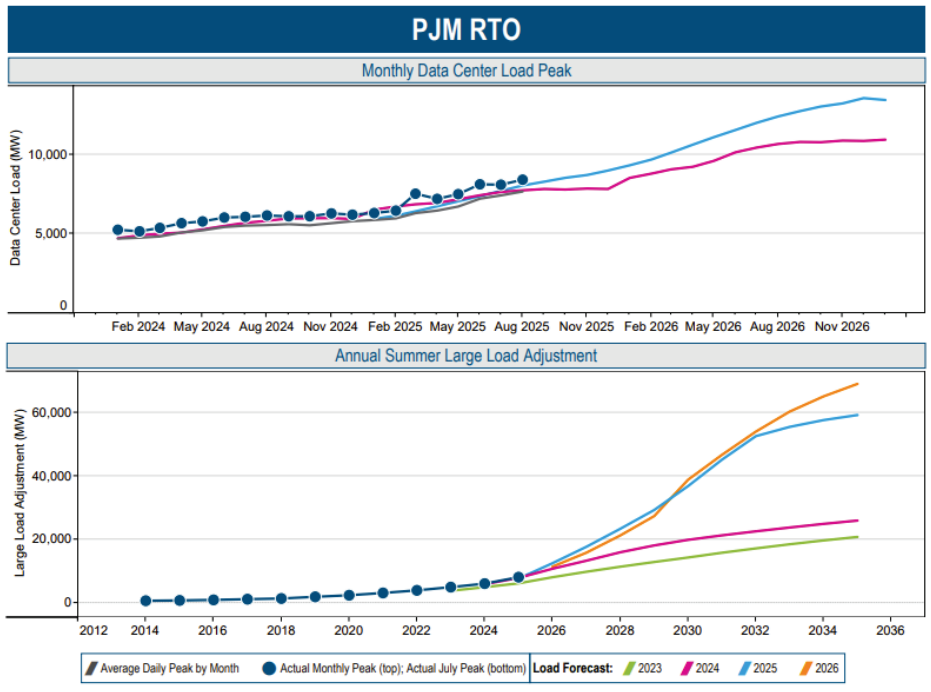
Figure A3-2. Distribution of 2025 large load peak demand and forecast to 2035



	DOM	AEP	COMED	PS	PL	DAYTON	PECO	ATSI	APS	PEPCO	JCPL	METED	DQE	BGE
2025	68.1%	21.1%	7.6%	3.1%										
2026	61.6%	23.5%	7.7%	2.7%	1.6%	0.0%	0.1%	1.1%	1.4%	0.0%	0.0%	0.0%	0.0%	0.2%
2030	35.8%	22.3%	13.3%	3.7%	12.9%	2.5%	2.1%	2.9%	3.1%	0.4%	0.2%	0.2%	0.1%	0.5%
2035	32.5%	23.6%	15.6%	3.8%	9.1%	3.3%	2.5%	3.1%	3.8%	1.4%	0.4%	0.3%	0.1%	0.5%

(3) Historical and forecasted monthly data center peak and annual summer large load adjustments for the PJM region and for each zone (figure A3-3).

Figure A3-3. PJM historical and forecasted monthly and annual large load forecast adjustments



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