NARUC
National Association of Regulatory Utility Commissioners

# Large Load Tariffs and Load Forecasting:
## Reducing Uncertainty in an Era of Load Growth


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*April 2026*

## Acknowledgments

This paper was written by Angela Navarro and Molly Knoll from Align Energy Advisors, for the National Association of Regulatory Utility Commissioners. It is based on work supported by the U.S. Department of Energy under Award Number DE-OE0000925.

The authors would like to thank the following individuals for their contributions, comments, and insights, which helped to improve the paper:

- **Peter Cappers,** Lawrence Berkeley National Laboratory
- **Tyler Fitch, Alyssa Perez, Lauren Shwisberg, Celia Tandon,** and **Sarah Wang,** RMI
- **Jeffrey Loiter,** National Association of Regulatory Utility Commissioners
- **Commissioner David Veleta,** Indiana Utility Regulatory Commission
- **John Wilson,** Grid Strategies

## Disclaimer

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# I. Executive Summary

Public utility commissions (PUCs) across the country need new tools to assess the forecast accuracy of utilities in this era of rapid load growth. Traditional load forecasting methodologies were not designed to account for the scale, timing uncertainty, and potentially speculative nature of current large-load interconnection requests. As a result, utilities risk either: (1) underbuilding infrastructure and jeopardizing future reliability, or (2) overbuilding infrastructure that may become stranded and lead ratepayers to bear unnecessary costs. In response to this load growth, many PUCs have approved large load tariffs aimed at minimizing stranded asset risk. These tariffs commonly include provisions such as minimum demand obligations, collateral requirements, phased load ramps, and eligibility thresholds intended to protect customers from the financial consequences of speculative load growth. While are often proposed as customer-protection mechanisms, these provisions also contain valuable information that PUCs can leverage to improve load forecasting accuracy.

This paper examines how PUCs can translate large load tariff provisions into load forecast inputs, including via planning assumptions and sensitivity analyses. Drawing on recent experience from Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), state commission decisions, and a growing body of academic and industry literature, this paper documents load forecasting risks, large load tariff provisions aimed at reducing such risks, and specific examples in action. The paper provides a review of current large load forecasting risk, a compilation of large load tariff provisions, a discussion of the relevancy of these tariff provisions to improved forecasting, and a four-part conceptual framework for operationalizing tariff design into improving forecast accuracy.

The conceptual framework includes four specific steps PUCs should consider when assessing utility load forecasts:

1. When to consider large load tariff terms in load forecasting;
2. Load characteristics that refine baseline forecasts;
3. Sensitivity and scenario analyses to assess risks; and
4. Updates over time using empirical queue and realization data.

This paper concludes with a hypothetical state example that operationalizes the conceptual framework. This example is intended to provide PUCs with detail on how to implement the framework in the absence of a real-world case study.

# II. Introduction

Load forecasting has long been a foundational element of electric utility planning and regulatory oversight. Long-term forecasts inform decisions regarding generation resource portfolios, transmission expansion plans, and distribution system upgrades. Shorter-term forecasts influence capacity market participation, reliability assessments, and operational planning.[1] PUCs assess the validity of these forecasts and their underlying assumptions, and then they rely on these forecasts to evaluate the prudence of future utility investments, the reasonableness of proposed rates, and the adequacy of resource planning processes.

Historically, forecast errors were driven primarily by population growth, marginal changes in end-use consumption, and other macroeconomic factors that were diffuse and incremental.[2] For example, population growth might exceed expectations, economic downturns might suppress demand, or energy efficiency adoption might outpace projections. While these uncertainties were significant, they tended to unfold gradually and affect large portions of a utility's load simultaneously. Forecasting methodologies evolved accordingly, relying on econometric models, trend analysis, and scenario planning.[3]

Today, the emergence of large, discrete loads has introduced a new challenge making it more difficult for regulators to assess the validity of utility forecasts. Interconnection requests from large, discrete loads require significant amounts of electricity. Each load is highly localized and requires dedicated, local infrastructure investments. These customers often seek access to electricity on timelines that are far quicker than the planning cycles and construction timelines of the typical electric utility.Regulators are thus confronted with a forecasting tightrope. Underestimating future load growth can result in insufficient resource procurement and reliability risks that slow or fully prevent the interconnection of new loads. Overestimating load growth can lead to overbuilding infrastructure resulting in stranded assets that increase costs on other ratepayers.

Large load tariffs have emerged as a key regulatory tool for managing some of these risks. These tariffs often require financial commitments, minimum contract terms, and phased development to protect existing customers from speculative risk. However, implementing a large load tariff is not the end of the consideration on minimizing and appropriately allocating risk between customer classes. Despite their growing prevalence, large load tariffs are rarely integrated explicitly into load forecasting methodologies.

Conceptually, large load tariff provisions reduce uncertainty around the timing, magnitude, and persistence of the large load.[4] This paper presents PUCs with the tools to identify and consider how the elements of these tariffs impact load forecasting risk. It provides PUCs with concrete recommendations to ensure that utility forecasts appropriately reflect the risk reduction mechanisms embedded in tariffs.

## A. Evidence of Forecasting Uncertainty Associated with Large Loads

The uncertainty associated with large load interconnection requests has emerged in a variety of forums. RTOs and ISOs are grappling with how they update their forecasts for regional transmission planning and/or capacity market contexts. Anecdotes of speculative projects abound in markets across the country. Research

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1 We focus this paper on load forecasts used in the short- and long-term utility planning process. Ratemaking forecasts are an additional subset of forecasts that are used to assess test year revenues, but they are not the subject of this paper.

2 Juan Pablo Carvallo, Peter H. Larsen, Alan H. Sanstad, & Charles A. Goldman, "Load Forecasting in Electric Utility Integrated Resource Planning," Lawrence Berkeley National Laboratory, October 2016, available at https://www.osti.gov/servlets/purl/1371722.

3 Ella Zhou, Sika Gadzanku, Cabell Hodge, Mike Campton, Stephane de la Rue du Can, & Jingjing Zhang, "Best Practices in Electricity Load Modeling and Forecasting for Long-Term Power System Planning," National Renewable Energy Laboratory (USAID-NREL Partnership), April 2023, available at https://docs.nrel.gov/docs/fy23osti/81897.pdf.

4 Tariffs can introduce their own uncertainties; most critically, a structural mismatch between the long-term planning horizons utilities require and the shorter contract visibility that tariffs provide. This gap can create new risks, including stranded investment and shifting cost burdens, even as tariffs offer the potential to improve the reliability of load projections.

papers and news articles give more granular context to the nature and context of this uncertainty. This section outlines these layers of evidence to ground the discussion of emerging solutions to reduce the underlying load forecasting risk.

## B. Regional Transmission Organization Experience

Recent experience across multiple regions demonstrates the magnitude of uncertainty associated with forecasting load growth from large load customers. RTOs and ISOs have publicly acknowledged that traditional forecasting tools are increasingly strained by the pace and scale of large load customer interconnection requests. These regional forecasts are built on the forecasts of the electric distribution utilities in their footprint, who are directly experiencing the interconnection requests.[5]

One example is PJM Interconnection (PJM), which continues to project significant growth in electricity demand over the next 20 years, including average projected summer peak load growth of 3.6% over the next 10 years.[6] However, in its 2026 Long-Term Load Forecast Report, PJM revised its near-term projected electricity demand downward from prior 2025 levels.[7] PJM attributed much of this decrease to improved vetting of adjustments for large loads, including a 0.7% reduction in the Summer 2026 peak demand as compared to the 2025 forecast.[8] PJM stated that "[n]ear-term forecast years need "firm" commitments, such as Electric Service Obligation (ESO)/Construction Commitments (CC), while longer-term projects will be considered "non-firm" and will be derated because of their greater uncertainty."[9] PJM's updated methodology reflects the year-over-year uncertainty inherent in load forecasting.

The Electric Reliability Council of Texas (ERCOT) has faced analogous challenges. In recent years, ERCOT experienced a surge in large-load interconnection requests, including 225 new interconnection requests from large load customers in 2025, representing an increase in demand of 270% since January of 2025.[10] In April 2025, ERCOT revised its load forecasting assumptions for large load customers to account for actual, observed uncertainty within the market.[11] The forecasting adjustments addressed some of the recent conditions ERCOT experienced, including an average project delay of 180 days and an average peak consumption for in-service data centers that was 49.8% of the megawatts ("MW") originally requested for study.[12]

Southwest Power Pool (SPP) has similarly acknowledged the need for new tools to assess load forecasts in this era of load growth. The annual energy usage in SPP increased by an average of 1.5% per year between 2019 and 2024, yet it grew by approximately 5% between 2024 and 2025.[13] Oil industry electrification represents 45% of the large loads in the SPP 2025 Integrated Transmission Planning Process (ITP), while data centers represent the second largest group at 23%. Reflecting on uncertainties in load growth, SPP has improved

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5 Get a Load of This: Regulatory Solutions to Enable Better Forecasting of Large Loads, RMI, February 2025 available at: https://rmi.org/insight/get-a-load-of-this/.

6 PJM Interconnection, "2026 Load Forecast Report," 2026, available at https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2026-load-report.pdf.

7 Id.

8 Jason McGovern, "PJM's Updated 20-Year Forecast Continues to See Significant Long-Term Load Growth," PJM Inside Lines, January 14, 2026, available at https://insidelines.pjm.com/pjms-updated-20-year-forecast-continues-to-see-significant-long-term-load-growth/.

9 Id.

10 Kristi Hobbs, "Item 16.2: System Planning and Weatherization Update," Electric Reliability Council of Texas Board of Directors Meeting, December 8-9, 2025, available at https://www.ercot.com/files/docs/2025/12/02/16.2-System-Planning-and-Weatherization-Update_Revised.pdf.

11 Electric Reliability Council of Texas, "2025 Long-Term Load Forecast Report," April 8, 2025, at p. 9, available at https://www.ercot.com/files/docs/2025/04/08/ERCOT-2025-Long-Term-Load-Forecast-Report.pdf.

12 Id.

13 Southwest Power Pool, "2025 Integrated Transmission Plan (ITP) — MOPC Education Session: September 23, 2025," September 23, 2025, available at https://spp.org/documents/74831/.pdf.

its forecasting model to account for extreme weather in the 2025 ITP. At the same time, SPP includes all the large load requests their load responsible entities (LREs) have submitted to the ITP "to get ahead of load growth projections."[14]

Each of these real-world examples illustrates the uncertainty that these entities are experiencing in bridging large load interconnection processes and load forecasting.

## C. Academic and Industry Literature

Academic and industry literature reinforces these observations on load forecasting uncertainty. A January 2025 analysis by Lawrence Berkeley National Laboratory estimated that data centers could consume between 6.7 percent and 12 percent of total U.S. electricity generation by 2028.[15] This wide range reflects uncertainty regarding AI adoption, efficiency improvements, siting constraints, and policy developments. Importantly, the analysis did not attempt to assign precise probabilities to specific outcomes, underscoring the inherent difficulty of forecasting large load customer interconnection requests.

The Electric Power Research Institute (EPRI) has also documented utility experiences with data center development, noting shared challenges across utilities in assessing the speculative nature of some of their service requests.[16] Grid Strategies reported that U.S. power demand forecasts were revised upward for three consecutive years, while noting that the forecast revisions could be an overestimate (or an underestimate) that is making it challenging for forecasters to agree on planning scenarios.[17] The Electric System Integration Group (ESIG) emphasized that large, discrete loads challenge traditional forecasting practices and require new analytical approaches, including recommendations on how to address the potential for duplicative projects.[18] For example, ESIG described Midcontinent System Operator's (MISO's) approach, stating that the ISO "infers that an applicant is developing multiple sites when a customer files common facility blueprints across locations, and it reduces the likelihood of each accordingly."

## D. Project-Level Uncertainty and Real-World Examples

Recent corporate announcements provide concrete examples of the uncertainty in large-load project development. In early 2025, Microsoft reportedly canceled up to two gigawatts of planned data center capacity reservations, reflecting changes in development strategy and market conditions.[19] Similarly, Tract canceled a 30-building proposal in the Phoenix area amid local opposition, water constraints, and permitting challenges.[20] These examples illustrate a critical point for regulators: even well-capitalized developers with strong track records may withdraw projects for reasons that are unrelated to the electric system.

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14 Id. at p. 32.

15 Lawrence Berkeley National Laboratory, "Berkeley Lab Report Evaluates Increase in Electricity Demand from Data Centers," Energy Technologies Area (Berkeley Lab), January 17, 2025, available at https://energyanalysis.lbl.gov/news/berkeley-lab-report-evaluates-increase-electricity-demand-data-centersLBNL analysis in January 2025.

16 Electric Power Research Institute ("EPRI"), "Utility Experiences and Trends Regarding Data Centers," September 16, 2024, available at https://www.epri.com/research/products/000000003002030643.

17 GridStrategies LLC, "Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers," November 2025, available at Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers

18 Energy Systems Integration Group ("ESIG"), "Forecasting for Large Loads: Current Practices and Recommendations," December 2025, available at https://www.esig.energy/wp-content/uploads/2025/12/ESIG-Large-Loads-Forecasting-report-2025.pdf.

19 Georgia Butler, "Microsoft Cancels Up to 2GW of Data Center Projects, Says TD Cowen," Data Center Dynamics, March 27, 2025, available at https://www.datacenterdynamics.com/en/news/microsoft-cancels-up-to-2gw-of-data-center-projects-says-td-cowen/

20 Audrey Jensen, "$14B West Valley data center project request withdrawn after cities push back," Phoenix Business Journal, May 2, 2024, available at https://www.bizjournals.com/phoenix/news/2024/04/29/tract-data-center-phoenix-buckeye-withdraw.html

# III. Overview of Large Load Tariff Provisions

Large load tariffs are designed to accomplish a variety of goals. Tariff provisions can mitigate the financial and operational risks associated with serving large load customers whose projects may not ultimately materialize. Tariffs are designed to appropriately allocate the risks and benefits of load growth across customer classes to ensure each group is paying its cost of service.[21] Large load tariffs can also attract these customers to a utility's service territory, driving economic development and tax base growth. In short, these tariffs are aimed at addressing risks and, in some instances, supporting other policy priorities.[22]

While tariff designs vary by jurisdiction, several core elements recur across approved tariffs, each with distinct implications for load forecasting. This section describes these core tariff elements that can be used to reduce speculation or forecasting risk. In reviewing these provisions the inter-related nature of large load tariffs is an important consideration. Contract lengths set expectations for how long a load will remain on the system, minimum demand obligations establish the utility's opportunity to recoup investments over that period, and capacity reduction or termination fees establish consequences for loads that exit the system early. These elements work together to manage large load risk and uncertainty. As commissions deliberate on the appropriate mix and specific requirements of tariff terms, each term should be evaluated within the context of the full tariff design.

At a high level, **Table 1** provides an overview of the foundational tariff provisions.[23] The chart then identifies whether the tariff element provides term and exit protections or financial commitments (or both), and how the provisions typically work.[24]

**Table 1: Overview of Large Load Tariff Elements**

| Tariff Element<br>*Type of approach* | How It Works |
|---|---|
| Eligibility Terms<br>*Term and exit protections* | These terms define which customers can or must participate based on their capacity, their load factor, or a combination of both. These terms also include whether the tariff provisions apply only to new loads or whether existing customers may opt in. By setting eligibility thresholds, utilities can focus risk mitigation measures on customers whose projects pose planning challenges. |
| Contract Length<br>*Term and exit protections* | These terms provide the length of time the large load tariff and any underlying terms and conditions will apply to the large load customer seeking to interconnect. The contract terms are often lengthier in time (ranging from 5 to 20 years) than typical tariff terms, ensuring that the forecasted load will be part of the system long enough to justify capital investments. While longer terms generally provide greater planning certainty, their effectiveness depends on the interaction between contract length and other tariff provisions, including termination rights, exit fees, and contract adjustment provisions. |

21 The underlying cost allocation framework is typically established in the utility rate case, which may take place in a separate proceeding.

22 For example, some large load tariffs include resource procurement options that enable direct investment from large load customers, such as Bring-Your-Own and Clean Transition Tariffs. These structures may also address state decarbonization objectives.

23 See also Satchwell, A., Mims Frick, N., Cappers, P., Sergici, S., Hledik, R., Kavlak, G., & Oskar, G., *Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities* (Technical Brief 11), Lawrence Berkeley National Laboratory, available at Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities.

24 Tariffs serve multiple purposes and each of the identified elements can also drive more than one policy outcome. For the purposes of this paper, each tariff element is categorized based on its primary relevance for forecasting.

| Tariff Element<br>*Type of approach* | How It Works |
|---|---|
| Minimum Billing or Demand Obligations<br>*Financial commitment* | These terms define the minimum demand payment for the customer. The terms typically provide that the customer must pay no less than a fixed percentage of their contracted demand, regardless of whether they actually reach their contracted demand. Some tariffs provide a breakdown of the minimum charges applied to generation, transmission, distribution, or all three. These terms are intended to provide strong signals of customer commitment to reduce the likelihood of stranded infrastructure investment. |
| Collateral Requirements<br>*Financial commitment* | These terms require the customer to provide increasing levels of collateral, which include deposits, letters of credit, and other forms of financial security. Many tariffs escalate collateral requirements as projects advance through the interconnection process, reflecting increasing certainty and risk sharing. Collateral requirements also mitigate downside risk by providing a source of funds to offset study costs, stranded investments, or interim capacity shortfalls if a project is delayed. |
| Load Ramp Period<br>*Term and exit protections* | These terms focus on phasing in the energization process for the large load customer, often according to predefined schedules of 4 or 5 years, rather than all at once. These provisions improve information transparency by specifying the timing and magnitude of incremental load increases. Load ramps serve both operational and planning objectives and have direct implications for load forecasting accuracy and infrastructure investment timing. |
| Contract Adjustments<br>*Term and exit protections* | These terms require advanced notice if a customer requests to adjust the expected contracted capacity. The terms could include scenarios such as delaying the date when the customer expects to fully achieve its contracted capacity or reducing the total level of contracted capacity. These provisions are frequently justified on the grounds that data center development is modular, iterative, and sensitive to rapidly changing market conditions such as compute efficiency or technological advances. At the same time, adjustment rights are often weighed and balanced against system planning risk, including terms such as longer notice periods and graduated adjustment schedules. While allowing a capacity adjustment introduces a level of uncertainty, a structured process with clear terms supports better forecasting and planning. |
| Capacity Reassignments<br>*Term and exit protections* | These terms define the process for utilities to work with the large load customer to reallocate unused generation or transmission capacity if the customer does not anticipate using the full contracted capacity it originally requested or exits the system. These terms often work together with termination fees, where the customer can reduce such fees if it can reassign capacity to another customer. These provisions reduce the long-term consequences of forecast error by preserving flexibility and enabling corrective action. |
| Termination or Exit Fees<br>*Financial commitment* | These terms set forth the financial penalties if a customer seeks to terminate its service or exit from the system. Termination and exit fees are triggered when a customer elects to discontinue service entirely or fails to proceed with development after executing a service agreement. The termination fees are often a meaningful percentage of the expected contract revenue, both to reduce the likelihood of departure without mitigation (such as via capacity reassignment) and to ensure that the customer covers some or all the cost of stranded assets if the customer elects departure without mitigation. |

The **Appendix** provides more detail on each of these tariff provisions, their impact on load forecasting, and real-world examples of terms, including language directly from tariffs, settlement agreements, and final commission orders.

# IV. Mapping Large Load Tariff Provisions to Load Forecast Inputs

Large load tariffs are often evaluated in isolation from load forecasting practices and are instead treated primarily as cost recovery and risk mitigation instruments. This section demonstrates that the tariff provisions outlined in the prior section can be mapped directly to specific forecasting inputs, assumptions, and sensitivities. Forecasting processes that incorporate large load tariff outcomes will provide PUCs with a more information-rich forecasting approach that captures the risk-reduction mechanisms inherent in the tariff.

## A. Overview of the Framework

At a conceptual level, load forecasting involves three interrelated questions: (1) the likelihood the load will materialize, (2) the timing and duration[25] of the load, and (3) how persistent[26] the load will be over time. Traditional forecasting models typically answer these questions using historical trends and macroeconomic indicators. Large load tariffs embed forward-looking information about individual projects that can refine each of these dimensions.

Tariff provisions related to eligibility, financial commitment, and minimum demand or billing obligations inform the *likelihood* and *persistence* of load realization. Contract length and load ramp provisions inform *timing* and *duration*. Capacity reassignment and termination provisions influence the *consequences* of forecast error and thus the degree of conservatism warranted in planning decisions. **Table 2** provides an overview of how each contract term can be applied in forecasting.

**Table 2: Tariff Elements and their Application in Forecasting**

| Tariff Element | Application |
|---|---|
| Eligibility Terms | Determines which loads require enhanced probabilistic treatment |
| Contract Length | Informs the duration of the load under baseline forecasts and scenarios |
| Minimum Billing or Demand Obligations | Narrows lower-bound forecast scenarios |
| Collateral Requirements | Adjusts inclusion weighting for early-stage loads |
| Load Ramp Period | Phases forecasted load growth |
| Contract Adjustments | Impacts sensitivities on load duration |
| Capacity Reassignments | Impacts scenarios and sensitivities on load duration |
| Termination or Exit Fees | Impacts baseline forecast and sensitivities on load duration |

This mapping illustrates that tariff provisions provide structured, regulator-approved limitations on project risks that can be translated into forecasting practice without requiring new data sources or modeling frameworks.

## B. A Recommended Conceptual Framework

While the mapping described above is straightforward, implementing it in practice requires changes to forecasting workflows and expectations. This section outlines a four-step framework to operationalize tariff information in load forecasting. The framework includes detail on which tariff information to include in baseline

25 For the purposes of this paper, load duration is how long the load is expected to remain on the system.

26 For the purposes of this paper, load persistence is how consistent the capacity factor of the load is over the contract term.

forecasts, sensitivity analyses, and planning scenarios. The framework is designed to be implementable using information utilities already collect through interconnection and contracting processes.

### Step 1: Determine Baseline Planning Assumptions Using Commercial Readiness and Financial Commitment Criteria

The first step in integrating large loads into forecasts is determining whether, and at what stage, a proposed load, or portion thereof, should be included in the utility's baseline forecast. The baseline forecast is the reference forecast that is developed using known policies, trends, and economic conditions. Rather than relying on queue presence alone, utilities should use indicators of commercial readiness and financial commitment, some of which are embedded in the tariff itself, to assess inclusion in the baseline forecast.

A tariff may set forth some principles that signal commercial readiness, while other principles are set forth in the utility's load interconnection process, such as the steps needed to move toward signing an electric service agreement (ESA).[27] These items provide useful commercial readiness indicators, including the attainment of non-ministerial permits,[28] demonstration of site control, and commencement of on-site construction. Commercial readiness indicators can also include interconnection milestones, such as negotiation of a letter of authorization, which is the contract initiating the transmission and distribution facility design and construction that often includes a financial commitment in the form of a deposit.[29] The next stage of the interconnection milestone occurs when the customer signs the ESA, which is the final, binding contract between the customer and the utility where requested demand is finalized. These milestones reflect progressively stronger evidence that a project will advance from concept to operation. These types of indicators can be balanced across a utility's queue management process and tariff provisions. For example, early-stage interconnection requests frequently precede site acquisition, permitting, or customer commitments and should therefore be treated with a lower degree of certainty when considered for inclusion in the baseline forecast or only partially included, as discussed below.

Financial commitment indicators reinforce these readiness signals. Tariff provisions requiring the posting of collateral, deposits, or other financial security provide observable and enforceable evidence of project seriousness. Escalating collateral requirements as projects move through the interconnection process further refine this signal. For forecasting purposes, projects that have executed interconnection agreements and posted substantial collateral are materially different from projects that remain subject only to preliminary studies and lower deposit thresholds.

Under this framework, PUCs should consider explicit thresholds for inclusion of large loads, or a portion thereof, in baseline forecasts such as evidence of site control, a letter of authorization along with a financial deposit, or execution of the final ESA. Loads meeting defined commercial and financial readiness criteria may be included, while loads that fall short should be excluded or discounted from baseline forecasts and addressed through sensitivity analyses.

### Step 2: Use Tariff Provisions Governing Load Shape and Duration to Inform Baseline Forecasts

Once a load clears the inclusion threshold, the second step is determining how that load should be represented in the baseline forecast. Tariff provisions governing eligibility criteria, contract length, and service configuration provide essential information about the expected shape and expected operational timeframe of the load.

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27 One important distinction is that until a load has a signed agreement with the utility and is taking service under the tariff, their requested demand under the interconnection agreement is not assured.

28 For the purposes of this paper, "non-ministerial permits" are defined as all necessary and discretionary governmental permits and approvals to construct a

29 A more detailed description of a standard interconnection process with key milestones may be found here: Energy Systems Integration Group ("ESIG"), "Forecasting for Large Loads: Current Practices and Recommendations," December 2025, available at https://www.esig.energy/wp-content/uploads/2025/12/ESIG-Large-Loads-Forecasting-report-2025.pdf.

Eligibility terms determine the size of the load that is subject to the large load tariff. It may also include a load factor, representing whether a customer is treated as a continuous, firm load or as a more flexible or interruptible resource. Contract length provisions establish the minimum duration over which load is expected to persist, informing assumptions regarding load longevity and amortization of infrastructure investments. Long-term contracts support stronger persistence assumptions, while short-term or easily terminated contracts warrant more conservative treatment.

Baseline forecasts should therefore reflect not only the size of contracted capacity, but also the profile of the load (firm or interruptible) and the duration of the load. Where tariffs require phased load ramps, baseline forecasts should incorporate those ramp profiles rather than assuming instantaneous realization of full demand. Including these tariff terms in the baseline forecast will help align planning assumptions with commission-approved tariff terms.

### Step 3: Use Tariff Provisions to Design Sensitivity Analyses and Planning Scenarios

The third step is to link tariff provisions to sensitivity analyses and scenario design. Even loads that qualify for inclusion in baseline forecasts introduce uncertainty that must be explored through alternative assumptions. The provisions in the large load tariff provide a structure to define the boundaries of sensitivity analysis and the creation of alternative scenarios.

Sensitivity analyses are designed to test the robustness of baseline planning decisions to variations in specific assumptions while holding the overall system context constant.[30] When considering large loads, sensitivities should explore uncertainty around the magnitude, timing, or persistence of individual loads that have already been deemed sufficiently likely to warrant inclusion in baseline forecasts. Eligibility terms, contract length, minimum billing or demand obligations, contract adjustment rights, capacity reassignment provisions, and termination or exit fees collectively establish many of the limits within which the behavior or persistence of these customers may vary. Sensitivities should therefore reflect how far actual outcomes could deviate from baseline assumptions while remaining consistent with tariff terms.

For example, a sensitivity analysis may assume realization of a lower threshold than the minimum demand obligation or the full contracted capacity, reflecting the downside risk that is explicitly contemplated and financially mitigated in the terms of the tariff. Similarly, where contract adjustment provisions allow partial reductions in capacity, sensitivities may explore reduced load levels that remain contractually permissible. Termination or exit fees may further bound these sensitivities by reducing the likelihood or financial impact of complete withdrawal. Finally, the utility should explore differing commercial readiness and financial commitment thresholds for the baseline forecast to determine whether the selected criteria create forecasting risk. By anchoring sensitivities in tariff provisions, utilities can present analyses that are both realistic and legally defensible.

Scenario analysis often serves a different purpose. Scenarios can be developed to explore structurally different future states that reflect broader uncertainty about market conditions and customer behavior.[31] Historically, scenarios evaluated variations in population growth, Gross Domestic Product (GDP), fuel and technology prices, technology advancement, trade, and specific energy policy interventions.[32] In the context of large loads, scenarios could be designed to capture uncertainty regarding the broader picture of demand across multiple projects and time horizons.

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30 Juan Pablo Carvallo, Peter H. Larsen, Alan H. Sanstad, & Charles A. Goldman, "Load Forecasting in Electric Utility Integrated Resource Planning," Lawrence Berkeley National Laboratory, October 2016, available at https://www.osti.gov/servlets/purl/1371722.

31 Ella Zhou, Sika Gadzanku, Cabell Hodge, Mike Campton, Stephane de la Rue du Can, & Jingjing Zhang, "Best Practices in Electricity Load Modeling and Forecasting for Long-Term Power System Planning," National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory (USAID-NREL Partnership), April 2023, available at https://docs.nrel.gov/docs/fy23osti/81897.pdf.

32 Id.

Importantly, scenario analysis may explore outcomes that go beyond the specific terms in the tariff, such as broader economic assumptions indicating project cancellations, widespread delays in development, or shifts in technology that impact demand intensity. They can also explore earlier stage loads that were not included in the baseline forecast. While such outcomes may not be explicitly contemplated by tariff terms, tariffs nonetheless inform the system-level consequences of these scenarios by allocating financial and operational risk between customers and ratepayers. Scenarios should also evaluate questions of how well the cost recovery mechanisms of the tariff will perform if some share of the tariff-qualified load fails to materialize or exits the system prior to the duration of the contract term. This approach improves analytical rigor and allows commissions to evaluate whether tariff designs and planning assumptions are properly aligned.

### Step 4: Update Forecasts Over Time Using Empirical Queue and Realization Data

The final step is iterative refinement. Large load forecasting should not be static, but it should evolve as projects advance or as information is gathered in the interconnection and project development process. Utilities collect substantial data that can inform this refinement, including the number of projects in the load interconnection queue, the timing and rates of advancement through queue stages, historical realization rates, and the differences between studied capacity and the profile of actual interconnected load.

Tracking queue attrition and advancement rates can help distinguish speculative interest from likely realization. Additionally, there is significant value in using realized outcomes to recalibrate forecasting assumptions and tariff designs.[33] Over time, this information can be used to develop discount rates for early-stage projects, refine inputs of the baseline forecast, and improve sensitivity analysis and scenario design.

PUCs should consider requiring utilities to periodically update load forecasts using this empirical information and to explain how observed outcomes have performed against prior forecasts and thereby informed changes in assumptions. This feedback loop enhances forecast accuracy, supports continuous improvement, and increases regulatory confidence in planning processes.

33 Natalie Mims Frick & Long Lam, "Large Loads: Interconnection, Tariff Designs, and State Actions," presentation (American Public Power Association Business & Financial Conference), The Brattle Group, September 8, 2025, available at https://www.brattle.com/wp-content/uploads/2025/09/Large-Loads-Interconnection-Tariff-Designs-and-State-Actions.pdf.

# V. Hypothetical Application of the Four-Step Framework

To better ground PUCs in how the four-step framework can work in practice, this section provides a hypothetical example of a state with new large load interconnection requests, a large load tariff the state PUC recently approved, and uncertainty on the extent to which load will materialize. The thresholds, outcomes and policy determinations in this example are purely to demonstrate the function of the framework and do not represent recommendations or best practices for real world application.

Pacifica Power Company (Pacifica) is a vertically integrated electric utility. It had a peak load in 2025 of 18,000 megawatts (MW). The service territory is a rapidly growing data center and advanced manufacturing hub. The utility currently has load interconnection queue requests from eight proposed data centers and two advanced manufacturing facilities totaling 8,000 MW of requested capacity representing over 40% of its current peak load.

The Public Utility Commission of Pacifica (Pacifica PUC) has recently approved a Large Load Service Tariff (Tariff) for Pacifica Power Company. **Table 3** summarizes how the Tariff addresses the various elements typically included in a large load tariff.

**Table 3: Elements of Pacifica PUC Large Load Service Tariff**

| Tariff Element | Terms |
|---|---|
| Eligibility Terms | Customers with a minimum contract capacity of 50 MW at a single site and a minimum load factor of 75%. |
| Contract Length | An initial contract term of not less than 10 years plus a 5-year load ramp period, for a total contract term of 15 years. |
| Load Ramp Period | A customer may elect up to a 5-year load ramp period with a minimum annual ramp of not less than 20% of contracted load. |
| Minimum Billing or Demand Obligations | The customer will have a minimum billing demand of 80% of the customer's contracted demand. |
| Collateral Requirements | The amount of collateral required is equal to 24 multiplied by: (a) during the first year of the contract, the maximum expected monthly non-fuel bill; or (b) after the first year of the contract, the Large Load Customer's previous maximum monthly non-fuel bill.A Large Load Customer with a credit rating of at least A- from S&P and A3 from Moody's and liquidity greater than ten times the Collateral Requirement shall be exempt from the Collateral Requirements. |
| Contract Adjustments | A Large Load Customer may reduce its contracted capacity during the contract term: (1) by up to 20% at no cost; and (2) by an additional 30% if another Large Load Customer agrees to assume the associated capacity. Each capacity reduction shall require a separate 36-month notice. |
| Capacity Reassignment | Pacifica will use reasonable efforts to mitigate the Termination Fee amount owed or paid by the Large Load Customer by evaluating the opportunity to assign the terminated reduced capacity to serve new Large Load Customers, to expand service to existing Large Load Customers, or otherwise secure offsetting expected revenues. |
| Termination or Exit Fees | If the Large Load Customer terminates early, it is subject to a Termination Fee equal to the nominal value of the minimum monthly bill times the number of months remaining on the contract or 36 months, whichever is greater. |

Pacifica must now integrate this Tariff into its load forecasting process for its next integrated resource plan (IRP), which covers a planning timeframe of 15 years. The IRP is updated every three years.

## Step 1: Forecast Inclusion Thresholds

In establishing the procedural schedule for the Pacifica IRP, the Pacifica PUC provided guidance that Pacifica should only include Large Load Customer projects in the baseline utility forecast if they have: (1) demonstrated site control, (2) reached the interconnection milestone of a signed letter of authorization, and (3) paid an interconnection deposit of $25 million for every 200 MW of requested contract demand. **Table 4** lists the large load projects in Pacifica's project queue.

**Table 4: Pacifica's Queue Snapshot** (2026)

| Project | Type | Requested MW | Signed Letter of Authorization | Deposit Paid | Site Control |
|---|---|---|---|---|---|
| 1 | Data center | 800 | Yes | $100M | Yes |
| 2 | Data center | 1,000 | Yes | $125M | Partial |
| 3 | Manufacturing | 270 | No | $5M study deposit | Partial |
| 4 | Data center | 750 | Yes | $75M | Yes |
| 5 | Manufacturing | 430 | Yes | $50M | Yes |
| 6 | Data center | 1,300 | Yes | $2M study deposit | No |
| 7 | Data center | 1000 | No | $125M | Yes |
| 8 | Data center | 850 | No | $10M study deposit | No |
| 9 | Data center | 1200 | Yes | $150M | Yes |
| 10 | Data center | 400 | No | $2M study deposit | No |

Based on the Pacifica PUC's guidance project readiness criteria, Pacifica would include the following projects in its baseline forecast:

- Project 1 (800 MW)
- Project 2 (1,000 MW)
- Project 4 (750 MW)
- Project 5 (430 MW)
- Project 9 (1200 MW)

The total load from Large Load Customers in the baseline forecast is 4,180 MW, rather than the full 8,000 MW in the Pacifica load interconnection queue. This provides more certainty to the Pacifica PUC on the underlying assumptions in the peak load forecast. Rather than allowing all loads in the queue to impact the forecast, Pacifica instead only includes projects demonstrating a minimum level of commercial and financial readiness.

## Step 2: Representing Load Shape and Duration

After determining which loads to include in the baseline forecast, Pacifica will then model the shape of those loads. The Large Load Service Tariff includes relevant terms to help inform both the load shape and the duration of the load.

First, the Tariff includes both a 15-year contract term (5-year Load Ramp plus 10 Year Term) and a Termination Fee. Pacifica's model could assume that a project included in the baseline forecast will stay on the system once energized for the full 15 years. This could be a reasonable assumption to test in the baseline forecast, because the Termination Fee represents a significant penalty to avoid early termination. These Tariff terms help Pacifica inform the duration of the load.

Second, the Tariff includes a phased ramp period over five years at 20% per year. Pacifica's model could include the assumption that all five of its large load customers will ramp their load using this ramp period at the minimum 20% level. This Tariff term will help Pacifica determine the magnitude of the load as the load enters the utility's system.

Third, the Tariff includes an 80% minimum billing demand obligation. This term is designed to require the customer to pay a fixed percentage of their contracted demand regardless of whether they ultimately operate at the full contracted demand. At the same time, the term provides a financial incentive for the customer to reach a high load factor to avoid paying for power it is not using. This term can help Pacifica determine the load shape after the ramp period, providing the assumption that the customer is incentivized to operate at a load factor of at least 80%. For a jurisdiction with only five large load applications included in the baseline forecast representing roughly 20% of peak load, the PUC might determine that only the load associated with the minimum billing demand obligation should be included in the baseline forecast, while the full contracted demand is considered separately in the sensitivities analysis.

Based on these terms, Pacifica could reasonably make three key modeling assumptions for the large load projects representing 4,180 MW of contracted demand in its baseline forecast, as shown in **Table 5**.

**Table 5: Load Forecast Modeling Assumptions Based on Tariff Provisions**

| Year | Realized Capacity (MW) | Forecast with Application of Minimum Billing Demand (80%) | Forecasted Peak Contribution |
|---|---|---|---|
| 2028 | 836 MW (20%) | 669 MW | 669 MW |
| 2029 | 1672 MW (40%) | 1338 MW | 1338 MW |
| 2030 | 2508 MW (60%) | 2006 MW | 2006 MW |
| 2031 | 3344 MW (80%) | 2675 MW | 2675 MW |
| 2032-2042 | 4180 MW (100%) | 3344 MW | 3344 MW |

The utility's baseline forecast now aligns the Large Load Service Tariff terms with realistic load shape, load magnitude, and load duration assumptions to inform its peak forecast. This provides the Pacifica PUC with information that is grounded in the Tariff terms.

## Step 3: Sensitivity and Scenario Analysis

Once Pacifica has established its baseline forecast, it could then test those assumptions through both a sensitivity analysis and planning scenarios.

### A. Sensitivity Analyses

Pacifica could test the Large Load Service Tariff terms using a sensitivity analysis to better understand uncertainty around the magnitude, timing, or persistence of loads included in the baseline forecast. For example, these sensitivities could test the boundaries of the minimum billing demand obligations, the contract adjustment rights, and the capacity reassignment provisions.

**Sensitivity 1: Minimum Demand Obligation Sensitivity**

Pacifica could run sensitivities assessing varying operational behavior of the large load projects. For example, in one sensitivity, it could evaluate if the large load projects operate on average at a 70% load factor on a long-term basis, rather than the 80% contemplated in the minimum billing demand obligation. It could also run a sensitivity if the projects instead operate at the full contracted capacity on a long-term basis. Under both sensitivities, the utility would assess whether the impact of the operational behavior is financially mitigated because of the Large Load Service Tariff terms.

**Sensitivity 2: Contract Adjustment Clause**

The Large Load Service Tariff allows a one-time 20% reduction in contracted capacity with 36-months' notice. Pacifica could run a sensitivity to assess the impact if some percentage of its projects utilize this contract adjustment term. For example, it could assume that two of its projects totaling 1800 MW of contracted demand request a reduction, resulting in a peak capacity reduction of 360 MW. Pacifica would better understand the economic impact of this sensitivity in which some level of capacity is reduced without financial mitigation.

**Sensitivity 3: Delayed Ramp**

In addition to capacity reductions, Pacifica could also assess the economic impact if projects do not energize on the timeline anticipated. For example, Pacifica could assume that a few of its large load customers experience construction delays resulting in a delayed ramp period. Alternatively, Pacifica could incorporate known delays in energization for proposed loads. To test these possibilities, Pacifica could model a sensitivity with the assumption that thirty percent of its large load customers experience a construction or energization delay of 2 years. This sensitivity would assess whether the collateral provisions or other Large Load Service Tariff terms provide adequate revenue protection for the utility in the case of delayed energization.

### B. Scenario Analysis (Beyond Tariff Terms)

In contrast to the sensitivity analysis, which will evaluate the limits of the Large Load Service Tariff terms, Pacifica could also develop various planning scenarios to assess the potential impact of broader economic impacts. The scenarios could include a scenario where there is a significant expansion in AI, and Pacifica receives a rapid escalation of large load interconnection requests. It could also test a scenario assuming there is a breakthrough in technology efficiency that could reduce the contracted capacity of large load customers long-term. These scenarios would test broader structural uncertainty.

**Scenario A: AI Boom Expansion**

Pacifica could explore a scenario where the AI industry experiences further rapid expansion due to technological innovation. For example, Pacifica could assume that projects that were excluded from the baseline forecast mature more rapidly than expected. In this case, Pacifica could explore a scenario where the full 8,000 MW will be energized by 2032. This scenario will provide information to the Pacifica PUC on the timing and scale of new investments needed to support that level of growth.

**Scenario B: Compute Efficiency Improvement**
On the other end of the spectrum, Pacifica could explore a scenario where breakthroughs in AI technology efficiency leads to a reduction in actual demand. For example, Pacifica could explore a scenario where large load demand is roughly 30% of the contracted demand on a long-term basis. This scenario would explore the broader limits of an overbuild scenario to better assess the economic impact to the utility and its ratepayers.

## Step 4: Iterative Refinement

Once Pacifica performs its first load forecast with these refinements in place, the Pacifica PUC should expect the utility to continue to compile empirical data reflecting the actual experience of projects moving through the interconnection queue and subject to the terms of the Large Load Service Tariff. This data would include the percentage of projects that placed interconnection study deposits but ultimately withdrew from the queue, the percentage of projects with a letter of authorization that moved to a signed ESA and energization, and the average timeframe from signing the ESA to the energization date.

This data could then inform whether Pacifica should apply any additional discount factors to projects that do not meet project maturity requirements for partial inclusion in future load forecasts. The data could also inform whether financial terms, such as Pacifica's interconnection deposits, are sufficiently protective. At the same time, as the data is collected, the Pacifica PUC should require load forecasting updates on an annual or more regular basis so that the forecast evolves over time in response to evidence-based criteria.

# VI. Case Study: Ohio AEP's Data Center Tariff and Interconnection Queue Response

Recent experience in Ohio provides a concrete illustration of how large load tariff design can directly reduce forecasting uncertainty by reshaping interconnection queue behavior. Following the adoption of revised data center tariff terms by AEP Ohio, the utility experienced a measurable change in the composition and volume of its interconnection queue from 30 GW to 13 GW.[34] This change demonstrates that tariff provisions can function not only as risk-allocation mechanisms, but also as filters that reduce speculative load requests.

AEP Ohio proposed revised tariff terms specifically tailored to large data center loads. These included eligibility requirements (25 MW or greater), increased financial commitments through deposits, minimum billing obligations (85% of contract capacity), longer contract terms (12 years), and termination fees (equal to minimum charges for 36 months after notice of termination).[35]

Following the implementation of the revised tariff, projects that were unwilling or unable to meet the new financial and contractual requirements withdrew from the queue or failed to advance to later interconnection stages.[36] AEP Ohio indicated that the revised tariff materially reduced speculative queue entries and improved the quality of information available for planning purposes.[37]

From a forecasting perspective, the AEP Ohio experience illustrates that tariff terms can reduce uncertainty, not only by reallocating risk after the fact but by preventing speculative load from entering planning assumptions in the first place. By increasing the cost of speculative queue entry through collateral, minimum billing, and longer-term commitments, the tariff reflected a filtering of projects based on readiness and commitment.

# VII. Conclusion

The rapid growth of large, discrete loads has revealed significant uncertainties in traditional load forecasting methodologies. Utilities and regulators face heightened risks of both underbuilding and overbuilding infrastructure, with implications for reliability, affordability, and public trust.

Large load tariffs represent a pragmatic and increasingly common regulatory response to these challenges. While typically framed as risk mitigation measures, these tariffs also generate valuable information about when projects will show up, how they will show up, their duration and commitment, and where there may be risk to the grid. However, when thoughtfully integrated into load forecasting practices, tariff provisions can help manage uncertainty, though their effectiveness depends heavily on how well tariff design aligns with planning timelines.

This paper presents strategies on how PUCs can view large load tariffs as integral components of modern forecasting frameworks. By aligning tariff design with forecasting methodologies, PUCs can better navigate the uncertainty inherent in large load customer interconnection.

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34 Zachary Jarrell, "AEP Ohio Cuts Its Data Center Demand Forecast in Half," Columbus Business First, September 25, 2025, available at https://www.bizjournals.com/columbus/news/2025/09/25/aep-ohio-data-center-demand-forecast.html.

35 See Public Utilities Commission of Ohio, *In the Matter of the Application of Ohio Power Company For New Tariffs Related to Data Centers and Mobile Data Centers*, Case No. 24-508-EL-ATA.

36 Zachary Jarrell, "AEP Ohio Cuts Its Data Center Demand Forecast in Half," Columbus Business First, September 25, 2025, available at https://www.bizjournals.com/columbus/news/2025/09/25/aep-ohio-data-center-demand-forecast.html

37 Zachary Skidmore, "AEP Ohio Slashes Data Center Pipeline by More Than Half," Data Center Dynamics, October 1, 2025, available at https://www.datacenterdynamics.com/en/news/aep-ohio-slashes-data-center-pipeline-by-more-than-half-report.

# Appendix

| Tariff Element | How it Works | Impact on Forecasting | State Examples |
|---|---|---|---|
| Eligibility Terms | These terms define which customers can or must participate based on their capacity, their load factor, or a combination of both. These terms also include whether the tariff provisions apply only to new loads or whether existing customers may opt in. By setting eligibility thresholds, utilities can focus risk mitigation measures on customers whose projects pose planning challenges. | Eligibility thresholds improve information transparency by clarifying which loads are subject to enhanced scrutiny and binding commitments. However, high thresholds may also leave smaller yet significant loads outside the tariff framework, increasing uncertainty for those projects. | **1.** AEP (West Virginia)[A]: After January 1, 2025, the following terms and conditions apply to new load, and to any expansion of existing load, so long as that new load or load expansion itself has a contract capacity greater than or equal to 100 MW at an individual site or 150 MW on an aggregated basis ('Large Load Customer').<br>**2.** Evergy (Kansas)[B]: The new LLPS rates will apply to: (i) any new facility beginning service after the effective date of Schedule LLPS with a peak load forecast reasonably expected to be equal to or in excess of a monthly maximum demand of seventy-five 75 MW at any time during the Term; or (ii) any existing customers with a monthly maximum demand that is reasonably expected to expand by seventy-five 75 MW<br>**3.** Otter Tail (Minnesota)[C]: The rate schedule will be available to greenfield Customers who reasonably demonstrate to the Company (1) an expected Metered Demand of at least 25 MW at a single Metering point, (2) an expected load factor of at least 80%, and (3) expected annual Energy sales of at least 175,000 MWh over 12 consecutive billing months. |
| Contract Length | These terms provide the length of time the large load tariff and any underlying terms and conditions will apply to the large load customer seeking to interconnect. The contract terms are often lengthier in time (ranging from 5 to 20 years) than typical tariff terms, ensuring that the forecasted load will be part of the system long enough to justify capital investments. While longer terms generally provide greater planning certainty, their effectiveness depends on the interaction between contract length and other tariff provisions, including termination rights, exit fees, and contract adjustment provisions. | The contract length helps to inform load forecasting assumptions regarding load duration and amortization horizons. Projects with long, firm contract terms may reasonably be treated as persistent load in baseline forecasts. Conversely, projects with short initial terms or early renewal options should be treated more cautiously, with load persistence modeled probabilistically or through scenario analysis. | **1.** Dominion (Virginia)[D]: The minimum demand charges calculated pursuant to Paragraphs IV. and VI. shall be applicable for ten (10) years from the Customer's execution of an Agreement for Electric Service following a capacity ramp period if new service is requested. The capacity ramp will consist of a four (4) year capacity ramp of 20% annual increments of installed capacity, starting with a year 1 minimum of 20% of installed capacity. At the beginning of year 5 throughout the end of year 14, the capacity will equal 100% of installed capacity. The contract term shall apply irrespective of generation suppliers. At the conclusion of the capacity ramp period plus ten years, the contract will automatically renew for additional one-year terms.<br>**2.** AEP (Ohio)[E]: Contracts under the Schedule shall be made for an initial period of not less than the Load Ramp Period plus 8 years. By way of example, the initial period of a Contract for a Data Center with a 4-year Load Ramp Period will be 12 years.<br>**3.** Otter Tail (Minnesota)[F]: Service under this rate schedule requires an ESA with a term of at least five years, with the term commencing on the first day of commercial operations. |

A See Appendix Endnotes, page 24

| Tariff Element | How it Works | Impact on Forecasting | State Examples |
|---|---|---|---|
| Minimum Billing or Demand Obligations | These terms define the minimum demand payment for the customer. The terms typically provide that the customer must pay no less than a fixed percentage of their contracted demand, regardless of whether they actually reach their contracted demand. Some tariffs provide a breakdown of the minimum charges applied to generation, transmission, distribution, or all three. These terms are intended to provide strong signals of customer commitment to reduce the likelihood of stranded infrastructure investment. | Minimum billing or demand obligations reduce downside risk and justify narrower forecast uncertainty bands. By shifting a portion of the financial risk associated with unrealized loads from ratepayers to the large load customer, these terms align incentives and improve confidence in projected demand levels and resulting forecasts. | **1.** Salt River Project (Arizona)[G]: [E]ach New Large Load Account will have a minimum billing demand (the kW used for calculating the per kW charge) of 80% of customer's forecasted demand (the "Minimum Billing Demand").<br>**2.** Dominion (Virginia)[H]: Customers with demands of 25 MW or greater and with a load factor of 75% or greater will be billed based on the greater of their actual measured demand or 85% of their stated contract demand for distribution and transmission charges, and 60% of their stated contract demand for generation charges.<br>**3.** Otter Tail (Minnesota)[I]: The minimum rate under this schedule shall recover the incremental cost of providing service, including any Energy-related marginal costs, the cost of additional Generation Capacity, the cost of network Capacity that is expected to be added while the rate is in effect, and any marginal Customer-related costs. The goal of this calculation is to ensure that the revenue requirement of other Customers will not increase due to the addition of the new large load. |
| Collateral Requirements | These terms require the customer to provide increasing levels of collateral, which include deposits, letters of credit, and other forms of financial security. Many tariffs escalate collateral requirements as projects advance through the interconnection process, reflecting increasing certainty and risk sharing. Collateral requirements also mitigate downside risk by providing a source of funds to offset study costs, stranded investments, or interim capacity shortfalls if a project is delayed. | Collateral requirements serve as a proxy for project seriousness and probability of realization. Customers who post substantial collateral are more likely to have secured financing, site control, and downstream demand commitments. Utilities may reasonably assign higher inclusion weights or confidence levels to projects that have satisfied higher tiers of collateral requirements. For example, projects that have posted only nominal deposits may be included only in sensitivity scenarios or discounted projections, while projects that have posted full construction collateral may warrant inclusion in baseline forecasts. | **1.** Alliant (Iowa)[J]: The Company may require the Customer to provide credit support, such as but not limited to, performance guarantee or letter of credit as determined by the Company. The credit support shall not be considered as an advance payment of bills for service to be rendered but shall be held as security for payment of obligations incurred on behalf of the Customer.<br>**2.** AEP (Ohio)[K]: The customer, if not having both (a) a credit rating of at least A- from S&P Global Inc. ("S&P") and A3 from Moody's Corporation (Moody's) and (b) cash and cash equivalents on an audited balance sheet prepared in accordance with Generally Accepted Accounting Principles (GAAP) (Liquidity) greater than ten times the Collateral Requirement, must provide a guarantee or collateral at the time of signing the contract equal to 50% of the total minimum charges for the full term of the contract ("Collateral Requirement"), calculated based on AEP Ohio's rates in effect at the time the Collateral Requirement is provided.<br>**3.** AEP (West Virginia)[L]: The customer shall provide collateral in a form acceptable to the Company based upon the creditworthiness of the customer. The amount of collateral provided shall be equal to 24 times the customer's previous maximum monthly non-fuel bill. During the first year of the contract, the maximum expected bill for the year shall be used. The amount of collateral to be provided will be recomputed annually, and updated if the recomputed value is 10 percent greater than the current amount held. |

| Tariff Element | How it Works | Impact on Forecasting | State Examples |
|---|---|---|---|
| Load Ramp Period | These terms focus on phasing in the energization process for the large load customer, often according to predefined schedules of 4 or 5 years, rather than all at once. These provisions improve information transparency by specifying the timing and magnitude of incremental load increases. Load ramps serve both operational and planning objectives and have direct Okay got implications for load forecasting accuracy and infrastructure investment timing. | Load ramps constrain timing uncertainty and allow infrastructure investments to be staged more efficiently. Traditional load forecasts often assume instantaneous increases in demand when large customers are energized, an assumption that can overstate near-term load growth and accelerate infrastructure investment unnecessarily. Load ramp provisions replace this assumption with a structured, time-phased growth profile that utilities can directly incorporate into forecast models. | **1.** Indiana Michigan Power (Indiana)[M]: A Large Load Customer may designate a Load Ramp Period, which can be no greater than five (5) years.<br>**2.** Dominion (Virginia)[N]: The capacity ramp will consist of a four (4) year capacity ramp of 20% annual increments of installed capacity, starting with a year 1 minimum of 20% of installed capacity.<br>**3.** Omaha Power (Nebraska)[O]: Customers must substantiate to OPPD's satisfaction that their Demand requirements will meet the minimum Demand requirements of this Rate Schedule within 18 months of establishing service under this Rate Schedule. |
| Contract Adjustments | These terms require advanced notice if a customer requests to adjust the expected contracted capacity. The terms could include scenarios such as delaying the date when the customer expects to fully achieve its contracted capacity or reducing the total level of contracted capacity. These provisions are frequently justified on the grounds that data center development is modular, iterative, and sensitive to rapidly changing market conditions such as computing efficiency or technological advances. At the same time, adjustment rights are often weighed and balanced against system planning risk, including terms such as longer notice periods and graduated adjustment schedules. While allowing a capacity adjustment introduces a level of uncertainty, a structured process with clear terms supports better forecasting and planning. | Contract adjustment provisions present an opportunity for more refined load forecasting. By explicitly defining the scope, timing, and limits of permissible adjustments, tariffs can provide planners with structured information about potential load variability. When integrated into forecasting methodologies, this information can support more realistic scenario analysis and stress testing via sensitivities. | **1.** Evergy (Kansas)[P]: Customers taking service under Schedule LLPS may request to reduce the Contract Capacity during the term or any extension term, with the effective date of any such reduction occurring at any time after the first five (5) years of the term by up to 25 MW or ten (10) percent of the Contract Capacity (whichever figure is lower on a MW basis) (Permissible Capacity Reduction) without charge for such reduction.<br>**2.** AEP (West Virginia)[Q]: A large load customer may, without payment of an Exit Fee or any penalty, reduce its contract capacity at any time after the first five years of the initial contract term by up to 20 percent, in total, by giving the Companies 42 months written notice prior to the beginning of the PJM Delivery Year for which the reduction is sought. Regardless of the number of notices provided, the amount of capacity reduction allowed is capped at a total of 20 percent.<br>**3.** Dominion (Virginia)[R]: A customer on Rate Schedule GS-5 may reduce its contracted capacity during the contract term: (1) by up to 20% at no cost; and (2) by an additional 30% if another customer agrees to assume the associated capacity. Each capacity reduction shall require a separate 36-month notice. |

| Tariff Element | How it Works | Impact on Forecasting | State Examples |
|---|---|---|---|
| Capacity Reassignment | These terms define the process for utilities to work with the large load customer to reallocate unused generation or transmission capacity if the customer does not anticipate using the full contracted capacity it originally requested or exits the system. These terms often work together with termination fees, where the customer can reduce such fees if it can reassign capacity to another customer. These provisions reduce the long-term consequences of forecast error by preserving flexibility and enabling corrective action. | Capacity reassignment terms may reduce risk of forecasting error, as the terms enable capacity to be reassigned to another customer. There are a number of variables inherent in this reassignment, such as whether the reassignment is in or near the same location as the original customer. As such, the reassignment terms can help produce more granular sensitivity and scenario analysis. | **1.** AEP (West Virginia)[S]: Following receipt of proper notice, through the Exit Fee Period, each Company will use reasonable efforts, consistent with its obligations as a public utility, to mitigate the Exit Fee amount owed or paid by the Large Load Customer by evaluating the opportunity to assign the terminated reduced capacity to serve new Large Load Customers, to expand service to existing Large Load Customers, or otherwise secure offsetting expected revenues.<br>**2.** Indiana Michigan Power (Indiana)[T]: Following receipt of proper notice, through the Exit Fee Period, the Company will use reasonable efforts, consistent with its obligations as a public utility, to mitigate the Exit Fee amount owed or paid by the Large Load Customer by evaluating the opportunity to assign the terminated/reduced capacity to serve new Large Load Customers, to expand service to existing Large Load Customers, or otherwise secure offsetting expected revenues. The remainder of any mitigating amounts owed to the Large Load Customer shall be delivered to the Large Load Customer, or its designated successor, after all outstanding balances have been resolved.<br>**3.** Evergy (Kansas)[U]: To the extent the customer seeks to reduce its Contract Capacity on less notice, and the Company can reasonably reassign Contract Capacity, the Company in its sole reasonable discretion may agree to a variance from these provisions. |

| Tariff Element | How it Works | Impact on Forecasting | State Examples |
|---|---|---|---|
| Termination or Exit Fees | These terms set forth the financial penalties if a customer seeks to terminate its service or exit from the system. Termination and exit fees are triggered when a customer elects to discontinue service entirely or fails to proceed with development after executing a service agreement. The termination fees are often a meaningful percentage of the expected contract revenue, both to reduce the likelihood of departure without mitigation (such as via capacity reassignment) and to ensure that the customer covers some or all of the cost of stranded assets if the customer elects departure without mitigation. | Termination and exit fees serve as a backstop against the most severe form of forecasting error: the complete non-realization or early departure of a large load after infrastructure has been constructed. Where a utility has invested in generation, transmission, or distribution assets sized to serve a specific customer, the loss of that customer can impose unrecovered costs on remaining ratepayers. Termination or exit fees are intended to place some or all of these costs on the departing customer and thereby reduce the likelihood the departure will occur. | **1.** Kentucky Power (Kentucky)[V]: Either party shall give at least five years' written notice to the other of the intention to discontinue service under the terms of this Schedule. Such notice shall not reduce the twenty-year initial term. In the event of a permanent closure by the customer occurring after the first five (5) years of the initial contract term, the customer may exit the contract by providing a one-time payment equal to five (5) years of minimum billing under this Schedule.<br>**2.** AEP (Ohio)[W]: After the initial term, Contracts shall remain in effect unless terminated by either party by providing written notice to the other party no later than three (3) years prior to the requested date of termination. After the initial term, either party may request a modification to the Contract Capacity by providing written notice to the other party no later than three (3) years prior to the requested modification date. During the initial term of the Contract, the customer will be financially responsible to pay the minimum charges regardless of the customer choosing to curtail, reduce, suspend, or terminate service. If after completion of the fifth year of the Contract after the Load Ramp Period the customer chooses to pay an exit fee equal to minimum charges for 36 months after notice of termination, the customer can thereafter terminate the contract. By way of example, a customer with a 3-year Load Ramp Period may pay the exit fee and terminate the contract only after Year 8 of the Contract.<br>**3.** Evergy (Kansas)[X]: To terminate or change rate schedules before the end of the Term or any Extension Term, the customer must provide written notice thirty-six (36) months prior to the requested date of termination or schedule change. If a customer terminates early, it is subject to an exit fee equal to the nominal value of the Minimum Monthly Bill times the number of months remaining or 12 months, whichever is greater (the Exit Fee). Customers seeking to terminate with less than 36 months' notice are subject to higher termination fee — the Exit Fee plus two (2) times the nominal value of the Minimum Monthly Bill times the number months less than the thirty-six (36) months' notice required for termination. |

# Appendix Endnotes

A Public Service Commission of West Virginia, Appalachian Power Company and Wheeling Power Company, Application for approval for revisions to Schedules LCP and IP, Case No. 24-0611-E-T-PW.

B The State Corporation Commission of the State of Kansas, In the Matter of the Application of Evergy Kansas Metro, Inc., Evergy Kansas South, Inc., and Evergy Kansas Central, Inc. for Approval of Large Load Service Rate Plan and Associated Tariffs, Docket No. 25-EKME-315-TAR.

C Minnesota Public Utilities Commission, Section 10.06, Electric Rate Schedule Super Large General Service, Applications and Eligibility Requirements.

D Virginia State Corporation Commission, Application of Virginia Electric and Power Company for a 2025 biennial review of the rates, terms, and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia, Case No. PUR-2025-00058.

E Public Utilities Commission of Ohio, In the Matter of the Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers, Case No. 24-508-El-RDR.

F Minnesota Public Utilities Commission, Section 10.06, Electric Rate Schedule Super Large General Service, Applications and Eligibility Requirements.

G Salt River Project Agricultural Improvement and Power District, E-67, Standard Price Plan for Large Load Substation, Large General Service.

H Virginia State Corporation Commission, Application of Virginia Electric and Power Company for a 2025 biennial review of the rates, terms, and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia, Case No. PUR-2025-00058.

I Minnesota Public Utilities Commission, Section 10.06, Electric Rate Schedule Super Large General Service, Applications and Eligibility Requirements.

J Interstate Power and Light Company, Electric Tariff filed with the I.U.C., Original Tariff No 1, Rider ICR – Individual Customer Rate.

K Public Utilities Commission of Ohio, In the Matter of the Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers, Case No. 24-508-El-RDR.

L Public Service Commission of West Virginia, Appalachian Power Company and Wheeling Power Company, Application for approval for revisions to Schedules LCP and IP, Case No. 24-0611-E-T-PW.

M Indiana Utility Regulatory Commission, In the Matter of the Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Power Tariff – Tariff I.P., Cause No. 46097.

N Virginia State Corporation Commission, Application of Virginia Electric and Power Company for a 2025 biennial review of the rates, terms, and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia, Case No. PUR-2025-00058.

O Omaha Public Power District, Rate Schedule No. 261M, Large Power – High Voltage Transmission Level – Market Energy.

P The State Corporation Commission of the State of Kansas, In the Matter of the Application of Evergy Kansas Metro, Inc., Evergy Kansas South, Inc., and Evergy Kansas Central, Inc. for Approval of Large Load Service Rate Plan and Associated Tariffs, Docket No. 25-EKME-315-TAR.

Q Public Service Commission of West Virginia, Appalachian Power Company and Wheeling Power Company, Application for approval for revisions to Schedules LCP and IP, Case No. 24-0611-E-T-PW.

R Virginia State Corporation Commission, Application of Virginia Electric and Power Company for a 2025 biennial review of the rates, terms, and conditions for the provision of generation, distribution and transmission services pursuant to § 56-585.1 A of the Code of Virginia, Case No. PUR-2025-00058.

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V Kentucky Power Company, Tariff Industrial General Service (I.G.S.), Special Terms and Conditions.

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X The State Corporation Commission of the State of Kansas, In the Matter of the Application of Evergy Kansas Metro, Inc., Evergy Kansas South, Inc., and Evergy Kansas Central, Inc. for Approval of Large Load Service Rate Plan and Associated Tariffs, Docket No. 25-EKME-315-TAR.

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