Forecasting for Large Loads

CURRENT PRACTICES AND RECOMMENDATIONS

A Report by the
Energy Systems Integration Group's
Large Loads Task Force

December 2025

ESIG
ENERGY SYSTEMS
INTEGRATION GROUP

About ESIG

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

ESIG Publications Available Online

This report is available at https://www.esig.energy/large-loads-task-force/forecasting/. All ESIG publications can be found at https://www.esig.energy/reports-briefs/.

Get in Touch

To learn more about the topics discussed in this report or for more information about the Energy Systems Integration Group, please send an email to info@esig.energy.

Forecasting for Large Loads: Current Practices and Recommendations

A Report by the Energy Systems Integration Group's Large Loads Task Force

Prepared By

John D. Wilson, Grid Strategies, project team lead

Sophie Meyer, Grid Strategies

Project Managers

Trieu Mai, Energy Systems Integration Group

Lisa Schwartz, Lawrence Berkeley National Laboratory

Project Team Editing Committee

Jenny Conde, Pacific Gas & Electric

Jeffrey Deason, Lawrence Berkeley National Laboratory

Natalie Mims Frick, Lawrence Berkeley National Laboratory

Christopher Gonzales, Salt River Project

David Farmer, National Rural Electric Cooperative Association

David Larson, Electric Power Research Institute

Luke Lavin, National Renewable Energy Laboratory

Debra Lew, Energy Systems Integration Group

Molly Mooney, PJM

Matteo Muratori, Pacific Northwest National Laboratory

Shivani Nathoo, Independent Electric System Operator (Ontario)

Nina Peluso, Energy Futures Group

Isabelle Riu, Energy and Environmental Economics (E3)

Lauren Shwisberg, Rocky Mountain Institute

Alison Silverstein, Energy Systems Integration Group

Anna Sommer, Energy Futures Group

Priya Sreedharan, GridLab

Jeffrey Sward, Rocky Mountain Institute

Other Project Team Members

Lin Chang, Western Electricity Coordinating Council

Nerlyn Echevarria, Dominion Energy

Grace Gaudin, Dominion Energy

Alexander Gordon-Sandweiss, Midcontinent Independent System Operator

Tyler Hackett, Vistra Corp

Donny Holaschutz, Inoudu

Marshall Klarfeld, Arizona Public Service

Kathryn Kline, National Association of Regulatory Utility Commissioners

Gregory Mandelman, EPE Consulting

Marissa Moers, Western Energy Board

Ross Mohr, Arizona Public Service

Daniel Nelli, Pacific Gas & Electric

Fernando Palma, U.S. Department of Energy

Benjamin Passty, Duke Energy

Shayan Rizvi, Northeast Power Coordinating Council

Katie Rogers, Western Electricity Coordinating Council

Victoria Rojo, Independent System Operator New England

Buxin She, Pacific Northwest National Laboratory

Rajesh Vaid, RMS Energy

Matthew Zapotocky, Western Electricity Coordinating Council

Zhi Zhou, Argonne National Laboratory

Disclaimer

This report was produced by a project team made up of diverse members with diverse viewpoints and levels of participation. Specific statements may not necessarily represent a consensus among all participants or the views of participants' employers.

Acknowledgment

This work was supported by the U.S. Department of Energy under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

Suggested Citation

Energy Systems Integration Group. 2025. *Forecasting for Large Loads: Current Practices and Recommendations.* A report by the Large Loads Task Force. https://www.esig.energy/large-loads-task-force/forecasting/.

Preface to ESIG Large Loads Task Force Reports

This report is one of eight reports by the ESIG Large Loads Task Force, which was formed to assist the power industry in addressing new challenges introduced by the rapid proliferation of large electronic loads such as data centers, as well as other large loads including manufacturing, electric vehicle fleets, and hydrogen production. The titles of the eight reports are listed here:

- Grid Integration of Large Loads: Introduction to the Larbe Loads Task Force, Data Needs, and Flexibility Overview
- Forecasting for Large Loads: Current Practices and Recommendations
- Interconnection Processes for Large Loads: Current Practices and Recommendations
- Large Load Performance Requirements: Current Practices and Recommendations
- Large Load Modeling for Dynamic Studies: Current Practices and Recommendations
- Transmission Planning with Large Loads: Current Practices and Recommendations
- Planning for Large Load Flexibility in Resource Adequacy
- Wholesale Market Design and Operations for Systems with Large Loads: Current Practices and Recommendations

Contents

Abbreviations

AI	Artificial intelligence
CAISO	California Independent System Operator
ERCOT	Electric Reliability Council of Texas
ESA	Electric service agreement
FERC	Federal Energy Regulatory Commission
IESO	Independent Electricity System Operator
ISO	Independent system operator
LBNL	Lawrence Berkeley National Laboratory
LOA	Letter of authorization
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NYISO	New York Independent System Operator
PUD	Public utility district
RTO	Regional transmission organization
SPP	Southwest Power Pool

Executive Summary

After two decades of relatively flat demand, the U.S. electricity system is projected to grow significantly over the next few years. Utility load forecasts project an increase in peak demand on the order of 166 GW by 2030, a 20% increase from estimated peak load in 2025. Data centers are expected to account for roughly 55% of projected demand growth, with other new large loads accounting for most of the remaining growth.

While there is consensus that several U.S. regions will experience significant load growth, its pace and scale remain uncertain. Reflecting that uncertainty, the same aggregate U.S. utility load forecasts from only three years ago, in 2022, projected peak demand growth of just 24 GW. Utility forecasters must manage this uncertainty to develop accurate forecasts that are used to inform resource and transmission planning.

Inaccuracies in load forecasts have important consequences. Load forecasts that underestimate actual demand can lead to both resource adequacy risks and a risk of under-serving customers due to insufficient infrastructure. Conversely, load forecasts that overstate demand could result in higher electricity prices to utility customers for energy facilities built in excess of actual need. If load forecasts are inaccurate, they make it hard for utilities to efficiently plan and construct the necessary generation, transmission, and other facilities needed to serve new large loads together with other loads.

Load forecasting is more difficult today than at any time in the past several decades. To date, the vast majority of load forecasts have used traditional econometric load forecasting techniques based on historical data. Most of that growth came from residential, commercial, and industrial customers whose individual loads were not often large enough to require special adjustments to the forecast. But emerging large loads—including data centers, manufacturing, and electric vehicle fleet charging—differ from traditional sources of demand growth. For most of the U.S. now, the large load forecast is *the* load forecast that matters.

Findings of the Large Loads Task Force

The lack of historical data on many of these new types of facilities and the rapidly evolving technology driving this load growth present novel challenges for load forecasters and grid planners. The Load Forecasting Project Team for ESIG's Large Loads Task Force offers the following nine findings.

Finding 1: Large load forecast methods lack transparency and consistency.

After reviewing over two dozen large load forecasts spanning diverse regions of the U.S., the project team found significant inconsistencies in how load forecasts describe and assess large loads. Ideally, each large load forecast would characterize and evaluate new loads using all five

FIGURE ES-1

Five Large Load Characteristics and Forecast Metrics

Project Realization	Energization Date	Load Realization	Load Ramping	Load Factor or Load Shape
The rate at which projects included in the load forecast are placed in service • Often presented as a percentage of project requests expected to come to fruition	The beginning of commercial operation by projects, including anticipated delays	The forecast peak load that the project is expected to require once it's fully scaled up • Often presented as a percentage of requested peak load	The monthly or annual forecast of demand during the startup period of commercial operation • Often presented as a percentage of requested peak load	• Load factor: Actual energy use as a proportion of facility capacity • Load shape: More detailed information on power needs, for example, an hourly schedule of energy use

Large load forecasts can characterize and evaluate new loads using five core metrics: project realization, energization date, load realization, load ramping, and load factor/load shape. Together, these describe whether, when, and how completely large load projects materialize and how they use electricity over time. Applying these metrics consistently improves comparability and transparency across forecasts.

Source: Energy Systems Integration Group.

metrics shown in Figure ES-1. These metrics can be applied both to individual project loads and to other energy and demand included in the large load forecast.

Finding 2: Customer-supplied data and historical data are currently insufficient for accurate forecasting.

For most load forecasts, large loads—particularly data centers—have become a planning challenge only in the past few years. Project maturity can affect whether projects are factored into load forecasts through the project realization metric as well as the degree of confidence applied to other load forecast metrics supplied by customers. Many utilities find customer-supplied data to be unreliable in certain respects, and because the load growth has occurred recently and suddenly, they have little historical data to rely on. Due to customer privacy and competitive business concerns, data sharing between utilities is rare. The resulting lack of data is a significant obstacle to accurate forecasting.

Finding 3. Load forecasts are using weighting methods and thresholds to evaluate prospective load.

While the new large load interconnection "pipeline" likely totals several hundred gigawatts of load, not every project discussed with utilities will be built. Utilities and regional grid planners are using several methods to estimate large load growth because many customer requests will not lead to completed projects (project realization), some completed projects will be smaller than initially requested (load realization), and completion schedules will slip (energization date and load ramping). To address these realities, load forecasts may simply exclude all requests that are not yet fully contracted for service. If a load forecast includes customer requests that are not yet fully contracted for service, the forecast may discount the load and may also adjust the schedule, accounting for delays relative to the customer's request. These weighting methods and thresholds reduce the large load forecast from several hundred gigawatts in the U.S. pipeline to a forecast that makes up the majority of a five-year load growth forecast of "just" 166 GW.

Finding 4. Some large load forecast practices insufficiently differentiate between types of large loads.

In addition to data centers, large load requests include several types of industrial and manufacturing facilities, oil and gas production loads, mining projects, and large fleet and public charging stations for electric vehicles. Yet some forecasts use the same weighting methods and thresholds for all types of large loads with little differentiation, despite substantive differences between load types. This practice is also common within broad large load categories, with different types of data centers forecast using the same weighting methods and thresholds. In many forecasts, the practices used for differentiating and forecasting large load types are not described transparently.

Finding 5. Data centers have distinctive characteristics that increase uncertainty compared to other large loads.

These characteristics include the following:

- Very large technology firms are developing data centers at multiple sites—sometimes served by a single utility but also spanning multiple regions. Shifting business plans and cancelling projects has greater potential to significantly reshape utility needs than project cancellations by other large load customers.
- Customer service requests from data centers often include incomplete engineering plans, yet seek rapid completion schedules.
- Data center development depends on an unusually complex set of supply chains and contractors. Collectively, these limited resources will constrain aggregate data center growth.
- Novel technologies, such as new artificial intelligence (AI) training, may yield load shapes that differ from those anticipated by the data center owner. While some utilities successfully apply historical data in planning for new large loads, gigawatt-scale AI projects are unprecedented.

Finding 6: Data center developers do not generally share alternative site locations and plans with utilities.

For the most part, individual utility large load forecasts generally do not consider whether prospective customers may be considering alternative sites within or outside their service territory because they lack awareness of those alternative sites. Some utilities and grid planners are introducing requirements for data center developers to report this information.

Finding 7: Most large load forecasts do not have much geographical detail for all proposed projects, only for contracted projects.

For prospective load, utility and regional system plans do not usually include specific locations for long-term load growth. That makes it difficult to plan how to build out the transmission system to serve future large loads individually and collectively.

Finding 8: Utility rate tariff reforms are helping to reduce load forecast uncertainty.

For example, one utility has significantly reduced its large load forecast after regulatory approval of a tariff that requires an applicable large load to meet certain development milestones.

Finding 9: Few large load forecasts include any meaningful consideration of load flexibility.

However, EPRI, the Lawrence Berkeley National Laboratory, and others are exploring large load flexibility as a means to more rapidly integrate new loads and reduce utility capital costs while meeting reliability and other grid needs.

Recommendations of the Large Loads Task Force

The Large Loads Task Force makes the following 10 recommendations on load forecasting.

Recommendation 1: Use all five large load metrics to create a large load forecast.

A well-structured large load forecast will clearly describe, collect applicant data for, and use the five large load metrics (project realization, energization date, load realization, load ramping, and load factor or load shape)

(Finding 1, Figure ES-1, p. xi) to characterize and weight information about large loads used to construct the large load forecast. Weighting factors for each load forecast metric could be informed by a maturity assessment, ideally as described in Recommendation 9. This can include thresholds for considering or excluding project information in load forecast development: projects that do not meet certain maturity thresholds may not be considered in the load forecast.

Recommendation 2: Develop a consistent framework to differentiate among types of large loads.

A large load classification system can help to consistently identify large load types across forecasts. Building a database of large load forecast metrics, as discussed in Recommendation 8 below, could inform a load classification system. A forecast that effectively differentiates among large loads will:

- Create classifications to include facilities with similar business purpose and load forecast metrics (project realization, energization date, load realization rate, load ramping rate, and load factor or load shape) and common characteristics such as size and site weather conditions

- Obtain and manage customer data by load type
- Develop a forecasting framework with modeling and validation practices that use similar data and methods for load types with similar maturity in terms of historical experience and predictability of outcomes
- For load types with different levels of maturity, differentiate modeling and validation practices to reflect the levels of uncertainty associated with each load and customer type, for all five large load metrics

Recommendation 3: Account for uncertainty.

Optimal planning of transmission and generation investments means accounting for uncertainty in both front-end and back-end risk. Front-end risks refer to uncertainty in the quantity and timing of infrastructure needed to serve new loads. To address these risks, forecasts are often structured around thresholds for project inclusion and weighting of project realization, load realization, and other load metrics to predict outcomes consistent with historical experience, using professional judgment. Back-end risks center on whether the infrastructure and investments built to serve new loads will remain used and useful over the infrastructure's lifetime. Many large load forecasts do not currently address back-end risks and overlook future attrition or systemic risk of customers reducing or cancelling service. This omission could lead to inefficient or excessive utility or regional infrastructure investments.

Recommendation 4: Increase certainty through large load financial requirements.

The main method used by utilities and regional planners to reduce near-term uncertainty is to modify tariff and contract requirements for large loads by requiring various forms of financial commitments and security from the applicant. Because so many large loads have huge financial resources, with single companies clustering several facilities on one utility system or building gigawatt-scale projects, such reforms by themselves are unlikely to remove all major uncertainties. Disclosure requirements and customer-sited generation are emerging practices to reduce uncertainty and financial risks for utilities, transmission planners and operators, and ratepayers.

Recommendation 5: Reduce uncertainty in regional large load forecast practices.

Consistent with Recommendations 2 and 8, regional transmission authorities and the Federal Energy Regulatory Commission are beginning to standardize requirements for customer-supplied information and formalize procedures for evaluating that information. This will help improve the accuracy of large load forecasts. While there are challenges to adopting a uniform interconnection request framework and forecast methodology, greater consistency in terminology, classifications, and ways that regional forecast methods relate to utility forecast methods could improve understanding and quality of large load forecasts.

Recommendation 6: Improve geographical detail.

Large load forecasts may need to incorporate information on large load project geographical locations by geographical zones or subregions and determine how to geographically allocate future large loads for planning purposes. This is particularly important for regional transmission planning authorities.

Recommendation 7: Seek continuous improvement through forecast validation.

As large load forecasting evolves and more information becomes available about the actual performance of large loads connected to the grid, it will be helpful to use this information to validate and improve future large load forecasting models and methods.

Recommendation 8: Collect large load forecast data in a shared database.

Nearly every large utility needs access to historical data for each type of large load, but most don't have such data. A national database would help solve this problem. Establishing such a database will require developing a framework for obtaining, managing, and protecting anonymized customer data; categorizing those data by large load type (Recommendation 2); and creating specifications for each large load metric. The database could begin with a simple set of metrics (including differentiating between large load types) and progress toward more complex metrics.

Recommendation 9: Apply consistent load-weighting and modeling practices.

In line with the North American Electric Reliability Corporation's preliminary draft reliability guideline, the electricity industry could adopt a project maturity assessment framework to define the phases of a large load project's development path and use them for consistent load-weighting and modeling for large load forecast development.

Recommendation 10: Adopt forecast standards for load flexibility.

As large load flexibility options evolve, large load forecasts could add load flexibility metrics used to characterize the loads in the forecast process (Recommendation 1) and treat flexibility consistently across all planning activities. While quantifying load flexibility services from data centers is challenging today, work is progressing to identify load flexibility strategies, including operational services as well as load management or reduction services, that could be included in load forecasts.

Introduction

After two decades of flat electricity demand nationwide, a new class of large loads is driving rapid demand growth, transforming planning and operation of power grids. These loads—including data centers, advanced manufacturing, hydrogen production facilities, electric vehicle fleet charging, and industrial electrification—differ from historical sources of demand growth.

Utilities and grid planners use load forecasts to inform future transmission system and resource needs. The power industry cannot efficiently plan and build necessary generation resources and transmission facilities without confidence in these load forecasts. If a load forecast is inaccurate with respect to the scale, timing, and location of changes in system load, then utilities and regional grid operators may fail to provide timely service to new customers or may build assets that will not be efficiently used over the course of their useful lives, incurring excess costs for customers. Load forecasting is critical for determining the need and timing of new energy infrastructure. This ESIG report supports efforts to improve forecasting for large loads.

The ESIG Large Loads Task Force adopted the definition by the North American Electric Reliability Corporation

(NERC) for a large load facility: "Any commercial or industrial individual load facility or aggregation of load facilities at a single site behind one or more point(s) of interconnection that can pose reliability risks to the [bulk power system] due to its demand, operational characteristics, or other factors" (NERC, 2025a). The lack of historical data for many of these types of facilities presents novel challenges for load forecasters and grid planners.

About 55% of currently forecast load growth is attributable to data centers (Wilson et al., 2025). Data center loads are particularly difficult to forecast because they are very large, they seek rapid interconnection to the grid, and their completion rate is more uncertain than large loads historically. These topics receive special emphasis throughout this report.

In recognition of these emerging challenges, NERC issued an industry recommendation on integration of large loads into transmission planning demand forecasts (NERC, 2025a), and the Federal Energy Regulatory Commission (FERC) has launched an investigation into this topic, as described in Box 1.

BOX 1

FERC Chair Rosner's Questions to Regional Transmission Organizations and Independent System Operators Regarding Large Load Forecasting, September 2025*

- How do you, the utilities in your footprint, and state regulators obtain information that verifies when and whether prospective large loads in your region will reach commercial operation?
- To what extent are prospective large load requests subject to consistent, objective screening criteria before they are included in the load forecast?
- How do you forecast how the actual electricity consumption of a large load will compare to its requested level of interconnection service?
- How do you coordinate with utilities at the regional or interregional level to share best practices on large load forecasting and ensure that large load interconnection requests are not double-counted?

* Federal Energy Regulatory Commission (2025a)

Differences Between Traditional Load Forecasting and Large Load Forecasting

A range of entities produce large load forecasts:

- Utilities forecast demand for their service territories, often using customer contracts, interconnection requests, and historical data when available.
- Independent system operators (ISOs) and regional transmission organizations (RTOs) develop regional forecasts for transmission planning and resource adequacy that incorporate utility data.
- Some regulatory bodies, such as the California Energy Commission, produce forecasts for use by utilities and regional planning authorities.
- Third-party market analysts forecast for investment and other business purposes, often with a short-term focus.

Forecasting practices are typically grounded in regression models based on historical trends for load and weather data, as well as macroeconomic and demographic indicators. More recently, load forecasting processes have been evolving to include adjustments for known new loads at the distribution level and new behind-the-meter distributed energy resources, such as solar and storage systems, electric vehicles, and building electrification technologies (ESIG, 2025).

However, these traditional forecasting approaches are ill-suited to emerging large loads. First, while general commercial loads follow population or economic growth patterns, emerging large loads do not correlate with either population or economic growth. Second, several of the dominant emerging large loads types—particularly data centers—are so new in some regions that few utilities have sufficient historical data for their service territories to construct statistical projections of future loads.

Based on the project team's research, a well-defined large load forecast would evaluate five key metrics for large load customers, as shown in Figure 1. These metrics jointly drive the forecast calculation of how much new large load demand will be added, how soon, and the associated energy use patterns over time. These metrics can be applied to both individual project loads as well as other loads included in the large load forecast.

Because many types of large load projects are forecast to have a project realization rate of less than 100%, the load forecast may consider other forecast metrics on a collective basis rather than on a project-by-project basis. The project realization metric can be thought of as the percentage likelihood that an individual project will move from proposal to completion and operation, and more broadly as the percentage of proposed large load interconnections that will mature to full operation.

The large load forecast informs transmission service requirements for these future customers. Any transmission-connected load needs an interconnection study to determine what upgrades are necessary to make the physical connection to the grid based on the characteristics of the load and existing transmission system conditions. (This topic is covered by the ESIG Large Loads Task Force report *Interconnection Processes for Large Loads*.)[1] For those large loads that require more power than the existing transmission system can reliably deliver, additional technical studies, permitting, and construction are necessary. This utility process can require 5 to 10 years from the forecast need to project completion, which may not align with the customer's desired energization date and load ramping plans.

Another key purpose of the large load forecast is to determine the impact of large loads on system generation and resource adequacy (Figure 2, p. 4). (This topic is covered by the ESIG Large Loads Task Force report *Planning for Large Load Flexibility in Resource Adequacy*.) Increased electricity demand can trigger changes in a utility's plan to acquire generation resources or a regional wholesale market's capacity requirements. The revised load forecast may drive almost immediate changes in resource procurement needs, even for loads that are not expected to energize for several years. This challenges the pace at which utilities and independent developers can permit and build new resources.

Large load forecasts can affect other types of power industry plans. For example, utilities may consider large

FIGURE 1

Five Large Load Characteristics and Forecast Metrics

Project Realization	Energization Date	Load Realization	Load Ramping	Load Factor or Load Shape
The rate at which projects included in the load forecast are placed in service • Often presented as a percentage of project requests expected to come to fruition	The beginning of commercial operation by projects, including anticipated delays	The forecast peak load that the project is expected to require once it's fully scaled up • Often presented as a percentage of requested peak load	The monthly or annual forecast of demand during the startup period of commercial operation • Often presented as a percentage of requested peak load	• Load factor: Actual energy use as a proportion of facility capacity • Load shape: More detailed information on power needs, for example, an hourly schedule of energy use

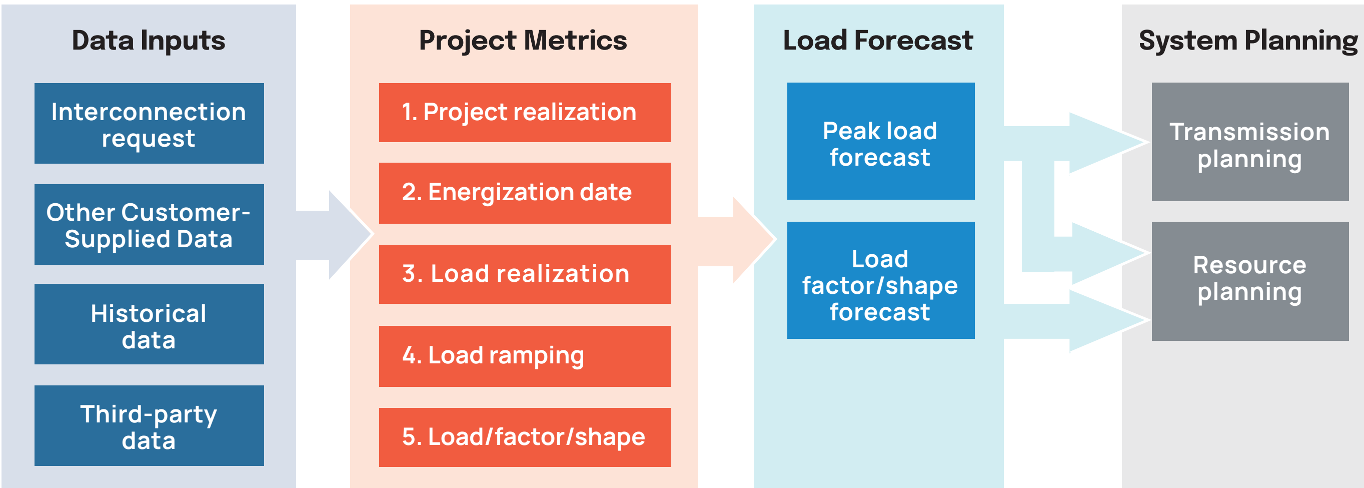
Large load forecasts can characterize and evaluate new loads using five core metrics: project realization, energization date, load realization, load ramping, and load factor/load shape. Together, these describe whether, when, and how completely large load projects materialize and how they use electricity over time. Applying these metrics consistently improves comparability and transparency across forecasts.

Source: Energy Systems Integration Group.

1 See https://www.esig.energy/large-loads-task-force.

FIGURE 2

Large Load Forecast Development for System Planning



The large load forecast informs both transmission planning and generation and resource adequacy assessments. Peak-oriented metrics guide transmission needs and timing, while all five metrics, including load factor and load shape, inform generation and resource planning. Accurate large load forecasts ensure that infrastructure is built at the right scale and pace to meet future demand.

Source: Energy Systems Integration Group.

load forecasts in capital budgeting and financial planning. Rate cases may also be affected if the utility uses forecast-based adjustments.

A few utilities include load forecasts in distribution planning. However, most large load forecast data lack the necessary locational granularity to identify impacts on specific distribution circuits until interconnection requests are received.

Forecast Uncertainty Compounded by Data Centers

Large load customers are requesting grid interconnection at a speed and scale not experienced in decades. The standard practice for generation and transmission plans is to take a long view, looking to optimize near-term projects with longer-term forecast requirements. However, data center customers are prioritizing “speed to power,” or the ability to energize their facility as quickly as possible. The speed and scale of large load requests may affect planning optimization practices with a scramble to meet near-term requests. Adapting these practices to provide service to the speed and scale of new customer requests means identifying and addressing several different uncertainties.

The most immediate uncertainty is project realization. Uncertainty around whether a prospective new customer will ultimately energize is nothing new to utilities—projects may be cancelled for any number of reasons. But project realization for data centers is more uncertain because individual data center developers often submit multiple interconnection applications across multiple utilities, planning to complete only some projects. Thus, for a given service area, only a portion of proposed data center projects are likely to be realized, with timing dictated by the progress of the developer’s other projects, whether due to the pace of interconnection or other business factors.

The Electric Reliability Council of Texas’s (ERCOT’s) experience demonstrates moderate project realization and load realization rates. ERCOT calculated that of the large load projects with load expected to be in service in 2024, 55.4% were actually in service by February 2025, and that for data center projects with in-service dates of 2022 to 2024, actual load was only 49.8% of the interconnection load request amount (ERCOT, 2025b).

The scale of data center load can increase the consequences of an errant forecast. Today, about half of data center project load planned to energize in the next several years is for projects 1 GW or larger (Wilson et al., 2025). For a utility that is anticipating a few GW of data center load growth, just one project cancellation can dramatically alter its load forecast and infrastructure requirements. Furthermore, data center projects can progress rapidly once approved. The potential for changes in a project's power requirements creates uncertainty for their energization date, load ramping, and realized demand.

Consequences of Inaccurate Forecasts

Where large loads become dominant drivers of anticipated growth, the consequences of inaccurate forecasts grow increasingly severe. Overestimating demand can lead to overbuilt infrastructure and stranded assets, increasing the price of electricity for all customers if the cost of required infrastructure is not fully recovered from the large load customers through charges and rates. Underestimating demand can lead to reliability shortfalls, rushed infrastructure deployment, and perhaps lost economic development opportunities. FERC Chairman Rosner cautioned that the difference of a few percentage points in electricity forecasts "can impact billions of dollars in investments and customer bills. Put simply, we cannot efficiently plan the electric generation and transmission needed to serve new customers if we don't forecast how much energy they will need as accurately as possible" (FERC, 2025a).

Large loads may not lead to higher bills for other customers. A recent study of factors influencing recent trends in U.S. retail electricity prices found that states with the highest load growth saw average prices decline in inflation-adjusted terms, while states with load reduction or contraction often saw prices increase (Wiser et al., 2025). The nature of grid investments as well as the rates and contract terms for large load customers will determine whether other customers see higher or lower costs.

Utilities face a delicate balance between their obligation to serve and the risk of stranded assets. Some large load customers are willing to accept reduced service levels in exchange for faster interconnection, while others want full service on rapid timelines. The way that utilities manage these trade-offs depends on the legal and regulatory frameworks governing each utility, as well as the utility's experience, judgment, and risk appetite.

Identifying Key Challenges and Developing Improved Practices

To address these challenges, ESIG convened a cross-sectoral project team within the Large Loads Task Force to focus on large load forecast practices. Participants included experienced forecasting professionals from utilities, ISOs, and RTOs; regulators; developers; consultants; and research organizations. The team explored existing electricity demand forecasting practices for large loads, identified key challenges in this space, and made recommendations to support improved practices.

The project team hosted a series of "Existing Practice Presentations" where 17 forecasting entities shared their modeling methodologies and lessons learned, explaining how their approaches have evolved over time with changing stakeholder needs and data availability. These presentations and practices, summarized in the section "Large Load Forecasting Practices Today," inform this report's findings and recommendations.

To provide readers with context for the size of large load growth, the section "2025 National Load Forecast" reviews recent studies of national and regional large load forecasts. In the sections "Using Available Data to Improve Forecast Accuracy" and "Developing New Information Resources and Forecasting Practices," the project team reviews potential improvements to large load forecasting practices.

Large Load Forecasting Practices Today

Large load forecasting practices vary widely across utilities and regions in North America.[2] Much of the attention to demand growth has rightfully been given to data centers, but in some locations just as much (if not more) near-term large load growth is forecast for manufacturing facilities, the oil and gas industry, and hydrogen production.[3] As a first step in this report, the project team met with 17 utility and regional load forecasting organizations to understand their load forecasts, the practices used to develop those forecasts, emerging challenges, and ideas for improvement. This section synthesizes the understandings from these conversations, attributing specific information only with permission.

It is timely that FERC Chairman Rosner has asked four questions about existing large load forecasting practices in the power industry (see Box 1, p. 2). These same questions are being asked throughout the power industry, and load forecasting practitioners seek to understand how other practitioners are responding to these challenges. This review gives particular attention to how utilities and regional entities incorporate project maturity, adjust customer-supplied data, and account for uncertainty.

BOX 2

Entities That Shared Their Existing Large Load Forecasting Practices

- Arizona Public Service
- Bonneville Power Authority
- California Independent System Operator
- California Energy Commission
- Dominion Energy Virginia
- Duke Energy (North and South Carolina)
- Electric Reliability Council of Texas
- Grant County Public Utility District
- Midcontinent Independent System Operator
- National Grid
- Northern Virginia Electric Cooperative
- Ontario Independent Electricity System Operator
- Pacific Gas & Electric
- PJM
- Salt River Project
- Santee Cooper
- Southwest Power Pool

Challenges to Large Load Forecast Quality

Project Data Sources

Utilities' first source of data is direct engagement with large load customers, but the quality and specificity of submitted data varies. Many, if not most, large load forecasts begin with data submitted in new customer interconnection requests. (This topic is covered in the ESIG Large Loads Task Force report *Interconnection Processes for Large Loads*.) Interconnection requests

2 This report focuses on U.S. load forecasting practices, with some input from Canadian entities. General assertions in this section should be understood as the project team's views after considering evidence in the existing practices presentations and a substantial database of documents from over three dozen utilities and other entities that perform load forecasts. The database was shared with all project team members.

3 As discussed in the section "2025 National Load Forecast," load growth in the transportation and buildings sectors is also expected, particularly in some regions in the 2030s. Adjustments to account for these sources of growth are discussed in the ESIG report *Long-Term Load and DER Forecasting* (ESIG, 2025).

establish a "pipeline" of projects that have met a minimal standard. While utilities track projects in the pipeline for workload and contextual purposes,[4] they typically begin to make financial commitments such as engineering work, equipment procurements, and construction scheduling only after the customers' projects reach a more advanced stage.

Most often, the long-term large load forecast is drawn from the interconnection request pipeline, reflecting the utility's view regarding realistic expectations of project development and operation. (Some utilities also extend the large load forecast to include load that is not attributed to specific projects.) Load forecast professionals explained that privacy protocols may limit the sharing and use of some customer-specific data included in those requests by the load forecasting team. Large load forecasts must often contend with customer interconnection schedule requests that are faster than usual utility timelines for generation and transmission planning. As a result of this timing mismatch, load forecasts may include adjustments to customers' schedule requests.

Utilities gather customer-supplied data from interconnection applications, letters of authorization, and electric service agreements (ESAs), and sometimes informal communications between utility account managers and large load developers. Some load forecast staff discussed challenges with the quality, format, and completeness of these submissions, which can be addressed using internal information, interpretation, or professional judgment.

In addition to customer-supplied data, some utilities incorporate external information sources such as public announcements, press coverage, or industry-specific tracking. For example, the Midcontinent Independent System Operator (MISO) has developed internal procedures to monitor media sources and financial filings that indicate future large load activity (MISO, 2024).

As will be discussed below, load forecasts often include adjustments to or replacements for customer-supplied data, including historical data with assumptions using internal professional judgment or historical evidence about similar loads. Professional judgment comes from:

- Subject-matter experts, whose input may be informal, ad hoc input or based on formal utility practice
- Formal, cross-departmental large load project review committees
- Structured scoring frameworks, using some combination of experts and committees

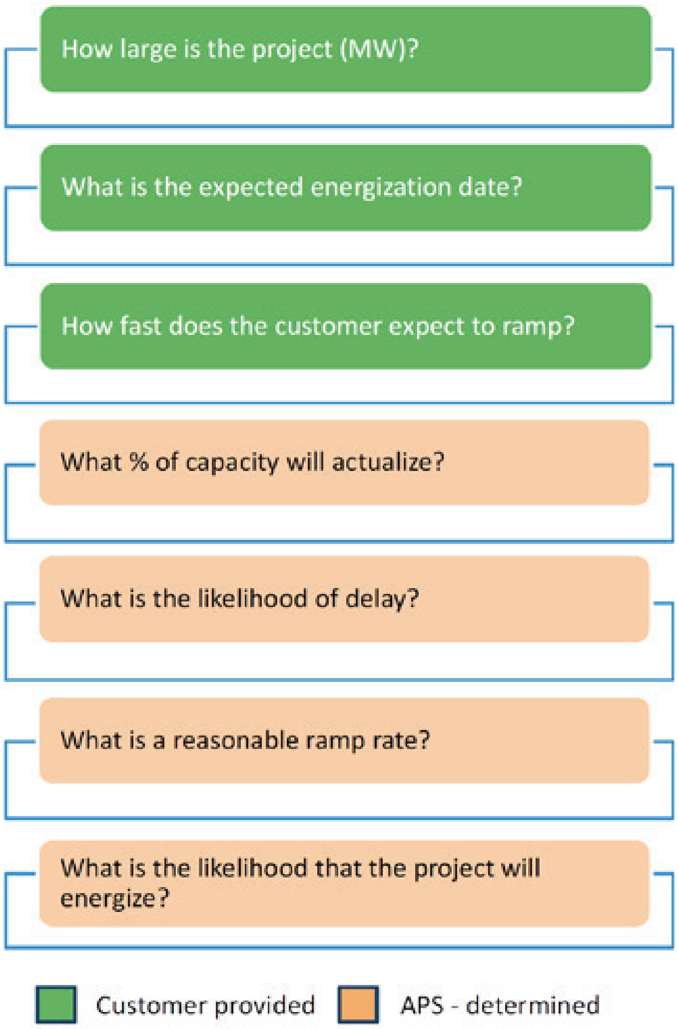
Arizona Public Service uses a mix of customer-supplied and utility-determined variables to inform its load forecast model, as shown in Figure 3 (p. 8).

Santee Cooper assigns points to multiple project criteria—including site control, transmission readiness, permitting and other constraints, and project capitalization—and weighs them to evaluate each potential customer. Scoring is based on customer-supplied information, historical data from the utility's existing customers, and other sources, as shown in Table 1 (p. 9).

4 Information about projects in the pipeline provide an indication of future engineering, procurement, and construction workload that is useful for business planning purposes. The total load requested for projects in the pipeline also provides context for the ultimate load forecast, so that the effects of forecast adjustments are understood.

FIGURE 3

Arizona Public Service Forecasting Process



Arizona Public Service (APS) integrates customer-supplied and utility-determined variables to develop its large load forecast. Inputs from customer and project updates are integrated on a monthly basis and, once combined with internal data and professional judgment, used to assess expected demand over time.

Source: Arizona Public Service, presentation to ESIG Large Loads Task Force Forecasting Team (June 2025).

Grounding assumptions for the load factor, ramp rate, and hourly shape in real-world operating behavior may seem like an obvious practice, but obtaining relevant data can be challenging. First, the utility must be able to identify comparable customers in terms of business type and operational goals, size, and desired speed to energization. Many utilities do not systematically collect or track customer business classifications, and smaller data centers can be difficult to distinguish from other commercial loads.

Second, there must be sufficient historical data—both in terms of years and number of customers—to support a meaningful baseline. Load forecasts in Northern Virginia, Silicon Valley, and Texas leverage over a decade of historical information on data centers (albeit smaller than many proposed data centers) and detailed customer data collection practices to develop large load forecasts.

For example, Dominion Energy Virginia has extensive historical data on data centers. Dominion develops an extended large load forecast based on more than 11 years of data center customer information. It creates customer-specific statistical models for its seven largest customers, some having more than one data center on its system, and an eighth model for all of its other data center customers. Dominion uses these models to create high, official, and low forecast scenarios (Dominion Energy, 2025a).

In contrast, many other utilities do not have significant data from their own territories. These utilities generally cannot access peer utility experience, because this information is not shared through public filings or industry channels due to customer confidentiality concerns. Furthermore, emerging technologies like artificial intelligence (AI) data centers differ significantly from other large customers in load profile and ramp dynamics (Shehabi et al., 2024). As a result, most utilities do not have a sufficient historical basis to develop standard large load forecast metrics.

Load Differentiation

Load forecasts usually include some differentiation of load types, such as manufacturing, data centers, and hydrogen production, but load type definitions are not consistent across load forecasts. Most utilities do not differentiate between large load types until they receive applications for grid interconnection from multiple types. A number of load forecasts do not identify any categorization of large loads, often because they include only one or a few individual large loads. Other forecasts only

TABLE 1

Santee Cooper: Potential Customer Evaluation Form

Potential Customer Evaluation Form

Topics	Questions		Checklist	Additional Notes
			Discussions	
Transmission Readiness	Is the transmission system ready for the customer currently? How long will it take to get the transmission system ready for the customer?		Feasibility	
			Scoping Study	
			Preliminary Design	
Location/Land	Has the land been purchased? Is the land ready to build on now or does it need to be cleared? How long will it take for the customer to become ready to connect?		Greenfield	
			Brownfield	
			Ready to Go	
Other Contraints	Is permitting going to be an issue? Is getting water going to be an issue? Are they in talks with multiple utilities? Anything else that might cause issues for the potential customer?		No concerns	
			Slight Conern	
			Major Concern	
Capitalization	Do they have financing?		Prepared Financing	
Historical Customer Most Similar (Optional)	Is there a customer (currently on the system or previously on the system) that this potential customer reminds you of? Did they come on the system at the load they said they would? How long did they take to come on?	Historical Customer		

Santee Cooper relies on an internal team of subject-matter experts from across departments to evaluate prospective large load customers. The evaluation form supports a weighted scoring system that assigns points for project readiness indicators such as site control, transmission availability, permitting status, capitalization, and other constraints. The resulting composite score informs assessed probabilities of project realization, energization delay, and load realization.

Source: Santee Cooper, presentation to ESIG Large Loads Task Force Forecasting Team (May 2025).

differentiate between generic data center and industrial and manufacturing projects, as shown in Table 2 (p. 10).[5]

The assumptions or practices for metrics used in a load forecast (ideally, the five metrics recommended in this report (see Figure 1, p. 3)) often vary depending on the type of load. But in many cases, utilities and regions do not use very many types of load in their forecasts. For example, few load forecasts appear to make meaningful distinctions among sizes and types of data centers (e.g., multi-tenant, crypto, AI, enterprise). The project team did not see any load forecasts that clearly identified the role of on-site generation in large load demand or energy metrics.

Methods for calculating load forecast metrics for large load projects often vary based on load differentiation. Some of the presentations on existing practices indicated a relatively high degree of confidence in customer data supplied for most industrial and mining (including oil and gas) large loads.[6] Among the reasons for that confidence is the long lead time in investment for these facilities, which gives the utility more time to understand the customer's request before moving the data into its load forecast. For many such projects, utility staff already have familiarity with the nature of the load or can obtain information about a similar facility that has an operational track record. This is reflected in the variation among specific types of industrial and manufacturing loads identified by utilities in Table 2: individual utilities find value in differentiating among types of customers that are important in their region.

Load forecasts usually include some differentiation of load types, such as manufacturing, data centers, and hydrogen production, but load type definitions are not consistent across load forecasts. Most utilities do not differentiate between large load types until they receive applications for grid interconnection from multiple types.

5 In some cases, a given load forecast uses load differentiation, but the categories are not disclosed and thus are not shown.

6 However, load forecast practices suggest lower confidence in the hydrogen production industry because it is subject to both rapid technological development and financial risks due to recent policy changes.

TABLE 2

Load Differentiation in Surveyed Load Forecasting Reports

Category	Load type	AEP	Alabama Power	Arizona Public Service	Bonneville Power Authority	California Energy Commission	Commonwealth Edison	Dominion Virginia	Duke Energy—Carolinas	Duke Energy—Midwest	ERCOT	Georgia Power	Grant County PUD	LGE/KU	MISO	National Grid	NOVEC	NV Energy	NYISO	Ontario IESO	PG&E	PJM	PSEG	Rappahannock EC	Salt River Project	Xcel Colorado
Data Centers	General	X	X	X	X	X	X		X		X	X	X	X	X		X	X	X	X	X	X	X	X	X	X
Data Centers	Cloud							X																		
Data Centers	Multi-tenant							X	X								X									
Data Centers	Enterprise							X																		
Data Centers	Fiber interconnection							X																		
Data Centers	Crypto/Blockchain	X						X	X		X	X	X													
Data Centers	Technology parks							X																		
Data Centers	Hyperscale								X								X									
Data Centers	Quantum computing						X															X				
Industrial/Manufacturing	General	X		X							X	X	X	X	X			X		X		X	X		X	X
Industrial/Manufacturing	IRA-boosted														X											
Industrial/Manufacturing	Steel								X	X																
Industrial/Manufacturing	Hydrogen										X				X				X							
Industrial/Manufacturing	Semiconductors						X		X										X						X	
Industrial/Manufacturing	Batteries						X		X			X		X								X	X			
Industrial/Manufacturing	Vehicles								X			X														
Industrial/Manufacturing	Food processing								X				X													
Industrial/Manufacturing	Port electrification																					X	X			
Industrial/Manufacturing	Water																	X								
Industrial/Manufacturing	Solar panels										X	X														
Other	Mining																	X							X	
Other	Oil and gas										X															X
Other	Electric vehicle charging					X										X					X	X				
Other	Medium- and heavy-duty charging					X															X	X				
Other	Casino																	X								

Note: Load forecasts without load differentiation were excluded from this table.

Source: Project team review of numerous public documents and information shared in presentations to the project team.

Data Center Load Forecast Uncertainty

There are several reasons why data center service requests may contain less certain or less detailed information than other types of large load customers:

- Many of the largest firms, such as Meta, Google, Microsoft, and Oracle are developing data centers at multiple sites across the country, with many gigawatts of growth forecast over the next five years (Kou, 2025). Some of their business models cast a wide, early net for potential projects and will cancel unneeded sites and applications later. This creates an uncertainty not typical for other types of large loads.
- Applications for data center interconnection are likely to be submitted before the facility's computing and engineering plans are fully developed and include schedules for rapid project completion. Multi-tenant data centers[7] may not be able to anticipate their tenants' exact computing and engineering plans, and therefore request maximum potential demand service capability to ensure that each tenant's requirements can be met in later build-out, sometimes years after the data center is placed in service with the utility. Potential tenants may be waiting for energy pricing and terms before signing a contract with the data center operator. As a result, even once the data center is energized, its energy use is difficult to predict.
- Data center development depends on the availability of a spectrum of engineering design, supply chains, and specialized contractors, many experiencing distinct growth challenges. The timing of these activities will affect a data center's initial energization date and the load ramp schedule. Since the supply chain for data center computing chips and other critical components is limited, market analysts suggest that growth of data centers will be constrained, affecting energization date and load ramping metrics (Elias et al., 2024).
- Many data center operators are applying novel technologies and business practices that will yield different load shapes than anticipated by the facility owner, even after full computing and engineering plans are developed. A few utilities have historical data for similar facilities that can be reasonably applied to new load requests, or may be able to obtain historical data from the customer from facilities in other utility service territories. But utilities lack historical data relevant to gigawatt-scale AI project interconnection requests.

For these reasons, participants in the existing practices presentations stated that, even with a signed contract, they have low confidence in the accuracy of customer-supplied load forecast metrics for data centers.

The confidence of interested parties in forecasts of data centers needs also to be considered when developing and explaining load forecast practices. For example, in a review of an integrated resource plan, one submission states:

> Putting a highly uncertain doubling of existing peak load into the Reference Case load forecast without being able to articulate the exact methodology used to determine this amount and its timing and without a single signed contract with a data center . . . is not a reasonable input for an [integrated resource plan] (Hotaling et al., 2025).

Limited confidence in large load customer data—both by utilities in their review of those data as well as parties to planning and other regulatory proceedings—is an ongoing challenge to effective load forecast practices.

Application of Weighting Factors Using Load Interconnection Milestones

Often, utilities apply weighting factors in developing load forecasts from customer-supplied data. Charles River Associates describes this practice:

> [Some] utilities—particularly those in regions where data center development is still nascent—rely on bespoke deterministic methods, often applying arbitrary derating factors or "haircuts" to data center projects in the pipeline. While this approach attempts to account for uncertainty, it lacks transparency and consistency, making it difficult to benchmark across jurisdictions. This methodological fragmentation reflects the broader challenge: the absence of a standardized framework for modeling high-density, high-variability loads, which complicates long-term resource planning (CRA, 2025).

7 Multi-tenant data centers are also referred to as co-located facilities. Since this can be confused with co-located generation, we use the term multi-tenant.

Utilities use load interconnection milestones to inform their forecast weighting practices and apply higher weighting factors as large load applicants progress through the milestones. These utility process milestones are established outside of the load forecasting process, reflecting varying terminology depending on the business practices of the utility or other load forecasting authority.

For purposes of this report, terminology for milestones that are typically important to large load forecasts is described in Box 3.

All utilities interviewed by the project team include the load from contracted projects in their forecasts at a high degree of likelihood. However, practices vary as to what

BOX 3

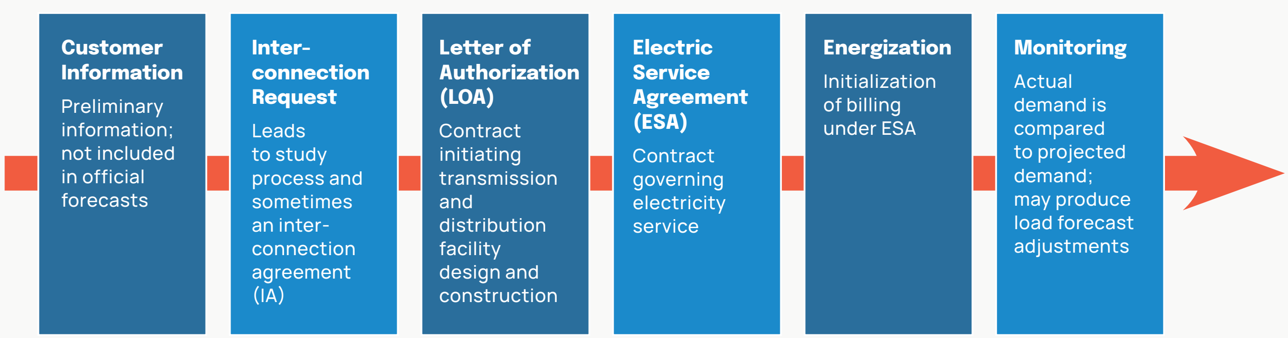
Interconnection Milestones

Terminology for utility process milestones that are typically important to large load forecasts are given in Figure 4 and summarized here.

- **Customer information**: Prior to the interconnection request, the customer almost always provides preliminary information to the utility. Regional power sector organizations may also collect preliminary information from a variety of public or informal channels. Utilities may track and aggregate preliminary information to understand emerging trends but do not rely upon such early-stage information for official load forecasts.
- **Interconnection request**: This is the formal request from the customer to begin the study process for interconnecting a load to a host utility, on either its transmission or distribution system. This usually leads to a **facility study**. Depending on the facility study results, there may also be an interconnection study, with the customer responsible for some or all of the identified costs, and then to an **interconnection agreement**.*
- **Letter of authorization** (LOA): This contract between the utility and its customer initiates the design, engineering, and construction of

FIGURE 4

Large Load Interconnection Milestones



Utilities track a series of milestones that mark a project's progression from early inquiry to full service. Each step—from preliminary customer information through interconnection requests, letters of authorization, and electric service agreements—provides increasing certainty about a project's scale and timing. The final steps, energization and monitoring, enable utilities to compare actual and forecasted demand, updating large load forecasts as real-world data become available.

Source: Energy Systems Integration Group.

* The details of these practices vary significantly across utilities and regional transmission organizations, and there may be multiple study processes available to customers of a single system. This topic is covered by the Large Loads Task Force report *Interconnection Processes for Large Loads* (https://www.esig.energy/large-loads-task-force/interconnection-process).

BOX 3 (CONTINUED)

Interconnection Milestones

transmission and distribution facilities identified in the facility study, and it almost always would involve a financial commitment from the customer. Sometimes the financial commitment may come in the form of a non-refundable deposit or a refundable advance to cover later new facilities charges. The LOA may be concurrent with the interconnection agreement or may be signed somewhat later.

- **Electric service agreement** (ESA): The ESA is the final contract with the customer, establishing the expected level of service and details such as the contract term, ramp rate, minimum billing, and financial security requirements.** Some utilities prefer to sign an ESA within the final year before energization to most accurately reflect actual service requirements, while others prefer to execute the ESA several years in advance to mitigate the risk that customers will be responsible for so-called "stranded costs."
- **Energization**: The energization (or commercial service) date initiates billing under the ESA. There may be electricity service during construction, but that would be provided under a different rate schedule.
- **Monitoring**: As the customer's demand ramps up, the utility or other planning authority may compare actual demand to customer-projected demand. It may be necessary to make adjustments to the load forecast and, consequently, transmission or generation resource plans.

** A full explanation of ESA terms is beyond the scope of this report and is expected to be explored in a forthcoming report by the Lawrence Berkeley National Laboratory.

exact milestone meets the definition of "contracted." Using the interconnection request milestone provides the utility with the most advanced planning but also the highest risk that the project may be revised or cancelled. At the other extreme, generation and transmission plans that lack information about projects prior to the ESA would likely result in a failure to build those resources to the necessary level of service, particularly for large loads on the scale of hundreds of megawatts.

Similarly, utilities vary in the level of financial commitment required from a large load customer at each milestone. As discussed in the section "Using Available Data to Improve Forecast Accuracy," these practices and policies are rapidly evolving.

Key Elements of Large Load Forecasts

Definition of Large Load

Many long-term forecasts do not include an explicit definition of large loads. Until recently, because there were few large load interconnection requests, the definition and handling of large loads was left to the discretion of load forecasting teams.

Historically, large load definitions have usually come from either planning categories or rate schedules. But as utilities receive interconnection requests for new gigawatt-scale loads, large load definitions and size thresholds are being reconsidered, and some utilities are establishing new large load customer classes. One report indicates that utilities are defining large loads in rate schedules as falling in the 25 MW to 100 MW range, with some also requiring load factors of at least 75% (Wood Mackenzie, 2025). Some examples of definitions of large loads, proposed or adopted for load forecast or planning purposes, include the following:

- Arizona Public Service defines extra-high-load-factor customers as having at least 5 MW demand and a load factor of at least 92%. This definition is used in both planning and rates (APS, 2024; APS, 2023).
- Dominion Energy Virginia has proposed a new high-load customer class (rate schedule GS-5) including

all customers with more than 25 MW contract demand and a 75% load factor (Dominion Energy, 2025b).

- NOVEC considers every data center as a large load.
- Ontario IESO defines large step loads as commercial and industrial projects (typically over 20 MW) that connect to the grid in large blocks (as opposed to slowly ramping up their growth over time) (IESO, 2025).
- Salt River Project considers a customer requiring a dedicated substation interconnection, typically 20 MW or greater, as a large load.
- The Southwest Power Poll (SPP) proposes to define high-impact large loads as projects with peak demand greater than 50 MW (SPP, 2025b; SPP, 2025c).

Where no "bright line" definition exists, the load forecasting practice can be somewhat informal. In reviewing whether to treat a project's capacity as part of a large load adjustment, the forecast may weigh the magnitude or the percentage of a zone's load.

The large load definition may be designed to avoid double-counting of large loads as both an "adjustment to" or within the traditional forecast (as discussed in the introduction). PacifiCorp defines a large load as an individual customer project over 50 MW. PacifiCorp excludes new large loads from the load forecast used for its integrated resource plan and plans for those loads outside that process. PacifiCorp explains that its proposed cost-allocation method requires that existing retail customers not bear the costs associated with serving new large load customers, whose needs are "met with incremental resources procured in accordance with the terms of special contracts or new tariffs" (PacifiCorp, 2025).

Project Realization

Project realization is the rate at which projects included in the load forecast are placed in service. Project realization is a relatively new metric for load forecasting because historically there were few large load customers and most matured into completed, energized projects. Today, because many types of large load projects are forecast to have a project realization rate of less than 100%, the load forecast may consider other forecast metrics on a collective basis rather than on a project-by-project basis. The project realization metric can be thought of as the percentage likelihood that an individual project will move from proposal to completion and operation and, more broadly, as the percentage of proposed large load interconnections that will mature to full operation.

Santee Cooper, for instance, uses a points-based process to assign separate probabilities to project realization and load realization. However, some load forecasts do not currently distinguish between project realization and load realization. Rather, they aggregate prospective loads by year and apply a single weighting factor to reduce annual loads into the future, without disaggregating the separate effects of project cancellation, reduction of load requirements, and potentially also delay in service (energization date).

Energization Date

The energization date is the schedule for when a load will be placed into commercial operation, including anticipated delays. The energization date metric is often presented as months of delay for each project that is then applied to the baseline load forecast, which could be the initial customer request or some later schedule provided by the customer.

Utilities typically draw initial energization date estimates from customers, particularly in interconnection applications and contracts. Most load forecasts appear to use a later start date than the date requested by the customer. Some utilities apply adjustments on a project-by-project basis, based on staff judgment or historical experience. For example, ERCOT recently considered applying a 180-day delay based on a historical experience of 218-day average delays (ERCOT, 2025a). Others, such as Georgia Power, apply an expected delay range, reflecting observed schedule slippage patterns across its service territory (Georgia Power, 2025). Publicly available information (e.g., supply chain constraints) is another consideration in setting the energization schedule. In general, load forecast practitioners express low confidence in dates supplied in the interconnection application, and higher, but not absolute, confidence for dates supplied in an ESA.

A key factor in forecasting a project-specific energization date is whether and when major transmission system upgrades will be completed to serve the project (Gramlich et al., 2024).[8] For example, Grant County Public Utility District has several hundred megawatts of new large load requests whose operation may be delayed from operation by up to seven years, due in part to the challenges of permitting and developing transmission facilities in an area with a high percentage of federal lands.

Load Realization

Load realization is the forecast peak load once new load projects fully ramp from energization to maximum operation and may be expressed as a percentage of requested or contract peak load. When calculated on a project-specific basis, forecast load realization may increase as a project progresses from interconnection request to full electricity service. Load realization may also be calculated on a historical basis for application as a weighting factor in load forecasts. For example, the California Energy Commission uses a load realization rate of 67% of the capacity requested for interconnection based on historical data from one utility (CEC, 2024).

Load realization weighting factors may be developed based on professional judgment or historical experience. For instance, Bonneville Power Authority and Arizona Public Service rely on staff expertise to adjust peak load assumptions. ERCOT, Dominion Energy, and NOVEC all report using experience from prior projects to inform expectations about peak demand. The load realization metric thus represents the cumulative application of forecast-specific definitions, practices, customer data, and internal information. Load-weighting practices and adjustments are explicitly described in a transparent load forecast.

The varying terms used to describe the total electrical demand of large loads can create confusion. This confusion can extend to internal metrics, particularly at data centers, as discussed in Box 4 (p. 16). In tariffs, the peak demand is often referred to as contract demand, as

The load realization metric represents the cumulative application of forecast-specific definitions, practices, customer data, and internal information. Load-weighting practices and adjustments are explicitly described in a transparent load forecast.

8 Generation interconnection queue backlogs and long lead times for delivery of high-voltage transformers and other critical equipment contribute to delays.

defined in an ESA. Even this may be imprecise, as some ESAs allow the customer's demand to exceed the contract demand based on either a defined margin or available interconnection capacity. This means that a customer's actual peak demand or billing demand could be more than or less than the contract demand, depending on ESA terms. But in large load forecasts, the peak demand does not always refer to contract demand. For example, some forecasts use the peak load provided in the interconnection application as a starting point.

Another factor in load realization can be the use of behind-the-meter generation. Many utilities have standby generation tariffs, which include charges for customers with on-site power generation that rely on the utility system for power when the on-site generation is in maintenance or otherwise insufficient for customer requirements.[9] Total potential customer demand during periods when it relies on the grid would need to be considered in the load realization metric.

BOX 4

Data Center Utilization

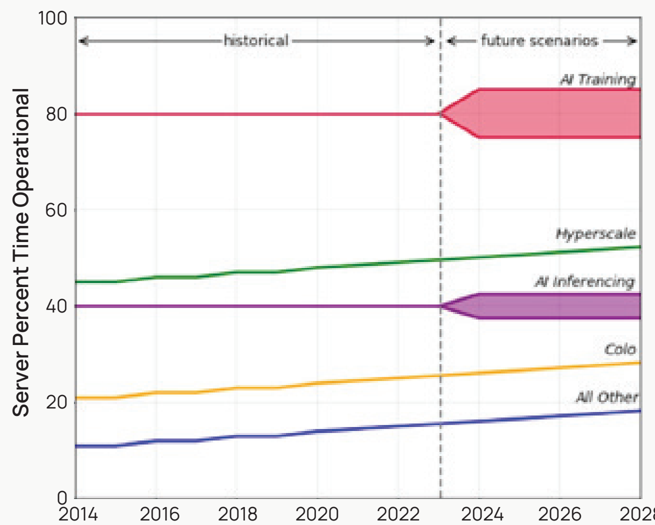
For data centers in particular, project load realization may be confused with server operational time or other metrics that are internal to the facility. Data centers do not run all the time, and, as shown in Figure 5, a server's operational time can vary widely depending on the type of data center.

Because data centers do not run all the time, even the peak power demand will fall below the rated or maximum (nameplate) power demand of servers and other equipment within the data center. The rated or maximum demand for internal equipment is only one input into the data center's electricity demand forecast; the project's energy and peak forecasts must also consider the planned workload and the server's operational time.

For example, a 25% server operational time is not in any way the same as a 25% load realization rate. If the customer correctly projects power use, then load realization should be close to 100% of forecast peak demand, even if server operational time is much lower. A good load forecast by the customer will incorporate the computing business model as well as the data center's electrical equipment load characteristics.

FIGURE 5

Data Center Server Operational Time by Type of Data Center



Server utilization within data centers varies widely by facility type and operational purpose. Because computing equipment rarely operates at full capacity, actual server run time represents only one input into a data center's forecast demand. In order to provide an accurate load forecast, the customer must consider both the computing business model and the data center's electrical equipment load characteristics.

Source: Shehabi et al. (2024). © The Regents of the University of California, Lawrence Berkeley National Laboratory.

9 If the on-site generation is metered separately from the customer's load, a standby generation tariff is not applicable, and the generator would probably not be considered in the load forecast.

Load Ramping

Load ramping refers to the monthly or annual forecast of demand during the period between initial project energization and reaching full forecast peak load.[10] Load ramping is typically expressed as a year-over-year (or sometimes month-over-month) increase in demand, reflecting how quickly a facility moves from initial load to its expected peak usage. For large facilities such as data centers or manufacturing plants, the load ramping period can vary widely depending on construction phases, equipment deployment, and business timelines. For example, Dominion Energy has found that load ramping varies by data center type, with crypto mining projects ramping very fast, cloud providers ramping in three to five years, and multi-tenant facilities ramping in five to seven years.

Most project load forecasts begin with load ramping schedules submitted in the interconnection application or ESA, which may be adjusted based on staff judgment or a formula based on historical experience. For example, Dominion Virginia relies on customer-provided information in a load letter at the outset of the project for the load ramping schedule (Dominion Energy, 2025c).

Some of the presentations to the project team on existing practices expressed low confidence in load ramping information supplied by customers. Load forecasts may include substantial modifications to customer submissions or even use standard load ramping metrics. Per the existing practices presentations, Arizona Public Service relies on staff judgment to adjust expected load ramping, Salt River Project relies on data center buildout experience, and MISO assumes a default load ramping schedule of 20% of peak load per year for data centers, continuing until the facility reaches its full projected demand.

Load Factor and Load Shape

The load factor and load shape for new large loads are particularly important for generation planning and resource adequacy assessments, for both reliability and economic reasons. Load factor is the actual energy use as a proportion of peak demand, and the load shape supplies more detailed energy use information such as an hourly schedule. For customers using on-site, behind-the-meter generation as their primary electricity source, any supplemental energy forecast of energy delivered from the grid to the large load customer would be considered as part of the facility's load factor and load shape. While a large load customer's peak demand is an essential input into load interconnection studies since it affects transmission buildout needs, the customer's impact on system demand across many hours is considered in a resource adequacy study. From a reliability perspective, grid stress may occur under various system conditions (e.g., not just the peak load hour).

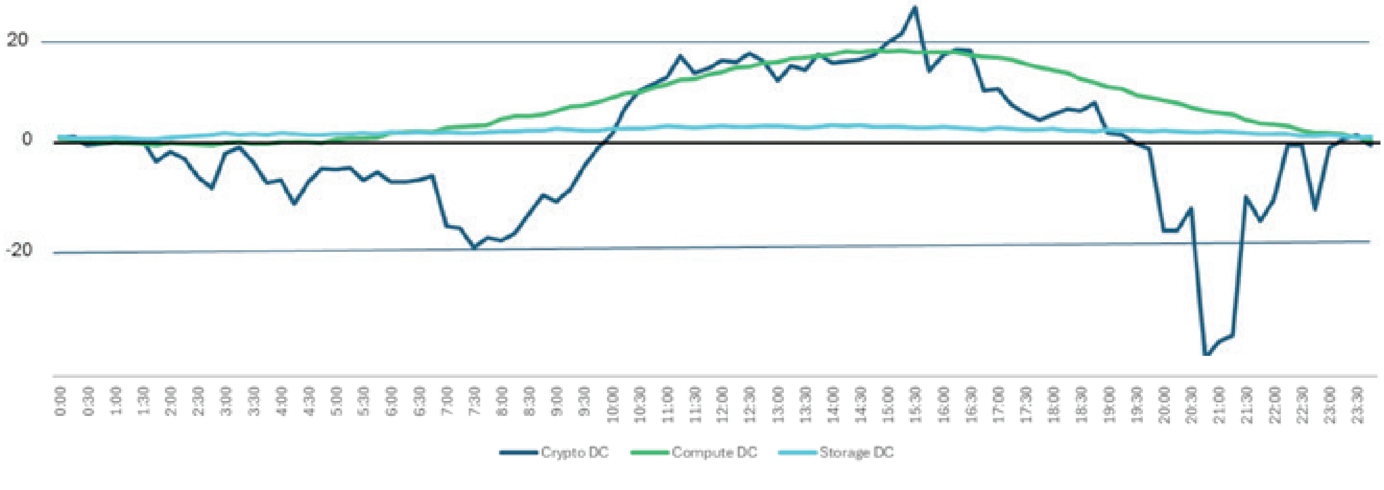
Load shapes affect electricity supply issues because the most economic supply resource selection depends on patterns of energy usage. A flat, high-capacity load requires a different resource mix than a weather-sensitive load. Given that a large load customer can use as much electricity as a city, that customer's hour-to-hour changes

Given that a large load customer can use as much electricity as a city, that customer's hour-to-hour changes in demand will be significant at a system level. Thus, planners need a reasonably accurate load shape representation to ensure adequate resources and effective grid operation.

10 This is as distinguished from electricity system load ramp rate, which refers to the overall system ramp rate on a sub-hourly basis. The system load ramp rate is not a focus of this report.

FIGURE 6

Typical Load Shapes for Data Center Types in ERCOT



Historical ERCOT data show substantial variation in hourly load patterns among different types of data centers. Crypto mining facilities exhibit steep reductions during periods of high wholesale energy prices, while cloud and enterprise facilities maintain steadier, higher load factors. These differences illustrate why using uniform load shape assumptions can misstate system impacts of large load additions.

Source: S. Morris, "Data Center Inside ERCOT Observations and Patterns," August 14, 2025, presentation to ERCOT Large Load Working Group, p. 3, https://www.ercot.com/files/docs/2025/08/11/LLWG_DataCenterObs.pptx.

in demand will be significant at a system level. Thus, planners need a reasonably accurate load shape representation to ensure adequate resources and effective grid operation.

Currently, many large load forecasts are based on project load factors from interconnection applications or contracts. But the load factor and load shape used in many large load forecasts often reflect adjustments based on staff judgment or historical experience. Load forecast practitioners often express low confidence in customer-provided load factor and load shape information, even when that information was provided in an ESA. Forecasters often modify data center load factor estimates with weighting factor adjustments, while accepting industrial customers with more established operational profiles and load shapes with fewer significant changes.

Some load forecasts, including those from the California Independent System Operator (CAISO), ERCOT, and PJM, leverage historical load shapes.[11] ERCOT has observed significant variation in load shapes for small data centers and crypto miners. Crypto mining facilities exhibit large load reductions during peak wholesale energy price hours, as illustrated in Figure 6. These data center load shapes are unlikely to apply to newer gigawatt-scale data centers, whose operational patterns will result in different load shapes.

Other load forecasts do not rely on customer data and assume a uniform load factor for all types of large loads. For example, MISO has used a 75% load factor for all large loads in its forecast. SPP states that it will use a utility's "hourly load shapes by [i]ndustry" if available, otherwise it will "apply a generic load shape for the specified industry" (SPP, 2025b). Other load forecasts, such as Pacific Gas and Electric's, use modeled load shapes (Riu et al., 2024).

Today, large load forecasts rarely consider load flexibility (as discussed in the section "Developing New Information Resources and Forecasting Practices"). While some emerging large loads may be capable of shifting demand or responding to price signals, utilities generally assume that most large loads have inflexible, non-dispatchable profiles. As noted in the New York Independent System Operator's (NYISO's) 2025 Power Trends report, this lack

11 Typically this would be a "12x2x24" load shape, with 12 months, 2 days (weekday and weekend/holiday) per month, and 24 hours per day.

FIGURE 7

Four Load Forecasting Practice Archetypes

	Exploration	Signed Contract	Future Planning
Deterministic Contract only	No projects are included	Firm contracted projects are included	No future projects are forecast
Deterministic Early-phase projects	Project inclusion is estimated	Firm contracted projects are included	Future projects may be forecast
Deterministic Extended forecast	No projects are included	Firm contracted projects are included	Future projects are forecast
Stochastic	Stochastic determination is applied at one or all stages		

Utilities use a variety of methods to create mid- and long-range forecasts for large loads. To understand the trade-offs in complexity and accuracy across different methods, this project identified four archetypes of large load forecasting practices. These are not (yet) "methods," as a load forecast method may include elements of different archetypes.

Source: Energy Systems Integration Group.

of flexibility consideration may limit forecasting accuracy as grid-interactive load technologies become more widespread (NYISO, 2025). When more loads—particularly large loads—can shift their loads to accommodate transmission availability and grid reliability needs, the surrounding utilities may not need to build as much new transmission and supply infrastructure to serve those loads.

Large Load Forecasting Methods

Large Load Forecasting Practice Archetypes

Utilities use a variety of methods to create mid- and long-range forecasts for large loads. To understand the trade-offs in complexity and accuracy across different methods, the project team identified four archetypes of large load forecasting practices.

The four archetypes shown in Figure 7 are not (yet) forecasting "methods," as a load forecast method may include elements of different archetypes. For example, American Electric Power uses a contract-only approach in the near term and includes some pre-contract projects in later years. NOVEC uses deterministic practices for certain steps in its load forecast while also conducting a stochastic analysis of other elements. Other load forecasts use one set of practices for certain types of load while using another set of practices for others.

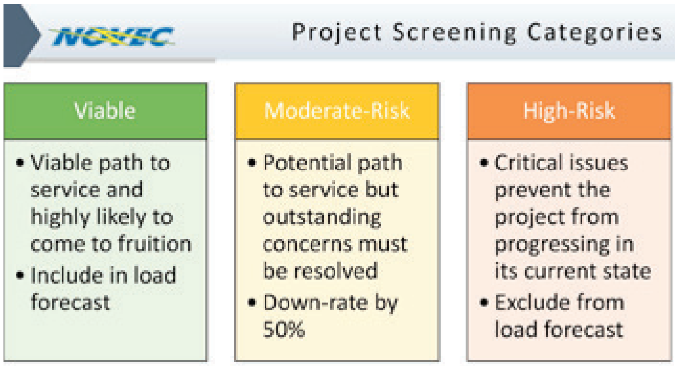
Contract Only–Deterministic: Projects Enter the Forecast Based on Progress Through a Contracting or Tariff Process

Contract-only deterministic practices limit the large load forecast to *only* projects that have achieved specific contracting or financial milestones. Common milestones include signed ESAs, executed interconnection agreements, or evidence of substantial financial commitment (e.g., payment for engineering studies or construction costs). Typically, these forecasts include contracted projects with a high likelihood of completion.

Practices for including contracted load in forecasts vary. For example, Exelon's 2025 large load forecast includes

FIGURE 8

Northern Virginia Electric Cooperative Project Screening Categories



NOVEC screens potential large load projects using tiered categories to assess likelihood of realization. Screening parameters include assessments of site control, firmness of site plan, viability of path to electricity service, and viability of path to zoning approval. The categorization allows NOVEC to consider more factors than contract status alone and informs which projects are incorporated into the load forecast and at what weighting.

Source: NOVEC, NOVEC Data Center Forecast, presentation to PJM Load Analysis Subcommittee (September 16, 2025), p. 13. https://www.pjm.com/committees-and-groups/subcommittees/las.

20 GW of projects with financial and construction commitments but applies an average 70% load realization rate to adjust the future load expectation down to 14 GW. Exelon's practices entirely exclude 45 GW of requests that lack a contract from its load forecast (Exelon, 2025). NOVEC also requires a contract to include large load projects in its forecast and applies screening factors, shown in Figure 8, to characterize project realization risk.

By focusing on known, committed projects, contract-only forecasting practices avoid over-forecasting risk associated with pre-contract projects. The intent is to align the forecast with highly certain infrastructure investment and procurement needs. However, requiring a contract potentially yields a load forecast that under-estimates actual demand. This can lead to resource adequacy risks and a risk of under-serving customer electricity demand by building less infrastructure than needed to serve all customers wanting electricity service.

Early-Phase Projects–Deterministic: Forecast Includes Both Contracted Projects and Those in Earlier Phases of Development

Because of concerns that contract-only forecasting criteria may understate long-term growth in fast-moving sectors, some load forecasts include pre-contract projects. Such customer loads may be weighted by project realization factors, load realization factors, or uncertainty regarding the ramp rate or energization schedule, reflecting the utility's understanding of project maturity. For projects assessed as having lower maturity, the project realization and load realization factors might

result in, for example, only 20% of project load requests being included in the load forecast. And that load might also be delayed longer than projects assessed at a higher level of maturity.

BOX 5

Oncor High-Confidence Load Criteria*

Concrete steps that provide confidence an agreement will be executed can include *two or more of the following*:

- Entering into an agreement with Oncor for preparatory activities for regulatory permitting, early engineering services, or advanced procurement
- Provision by the customer of specific project delivery details
- Proof of site control
- Completed water, wastewater, gas, or other site-related studies
- Attestations of non-duplicative load request
- Verification of the financial capabilities to proceed with project
- Payment of study fees

Oncor further explains that the reason it identifies some pre-contract projects as high-confidence loads is that:

> Historically, Oncor has not entered into formal agreements for interconnection unless an in-service date could be provided. Substantial new transmission infrastructure is required to serve many new Oncor loads. Until these transmission projects proceed through the ERCOT and [Public Utility Commission of Texas] processes, clear in-service dates are unavailable (Oncor, 2025).

* Summarized or quoted from Oncor (2025), and edited for brevity, emphasis, and formatting.

The use of weighting factors for pre-contract projects can also be combined with criteria for including those projects. For example, Oncor does not require a contract for a large load to be included in its forecast, but it does require two "concrete steps" to be completed, as shown in Box 5. Other forecasters include load realization below a certain threshold (e.g., 50%).

Utilities that include some level of pre-contract load in their large load forecasts do so because they are concerned about the long lead time to build and connect new generation resources or because they may fail to anticipate high-growth clusters of large loads. For example, the California Energy Commission's forecast of data center load uses data from interconnection applications collected from California utilities, as adjusted by project realization, load realization, and load ramping/energization date adjustments, as shown in Table 3 (p. 22).

Some load forecasts rely on data from customers that have not yet filed an interconnection request (Hotaling et al., 2025). These forecasts may over-forecast if their weighting factors are too high. For this reason, deterministic forecasts that include pre-contract load often include scenarios (e.g., high, baseline, and contract-only) that reflect alternative weighting practices, as illustrated by the California Energy Commission example in Table 3.

Extended Forecast–Deterministic: Extends Contract-Based Forecast Based on Growth Trends

Most large load forecasts flatten out in the mid-2030s, depending on ramp rate assumptions and whether pre-contract projects are included.[12] One exception is Duke Energy (Carolinas). Its 2025 load forecast includes 2,000 MW of projects through 2040 "reflecting continued economic development" in addition to all contracted large loads and a discounted portion of large loads with letter agreements and late-stage pipeline status (Duke Energy, 2025a, 2025b).

Another exception is Dominion Virginia, whose load forecast uses a large load customer-based statistical model of billing demands to project large load growth. Dominion

12 As an indication of this tendency, nationally aggregated forecasts (FERC Form 714) drop from 30 GW of load growth in 2030 to just 12 GW in 2033. (Grid Strategies, analysis performed for ESIG Large Loads Task Force.)

TABLE 3

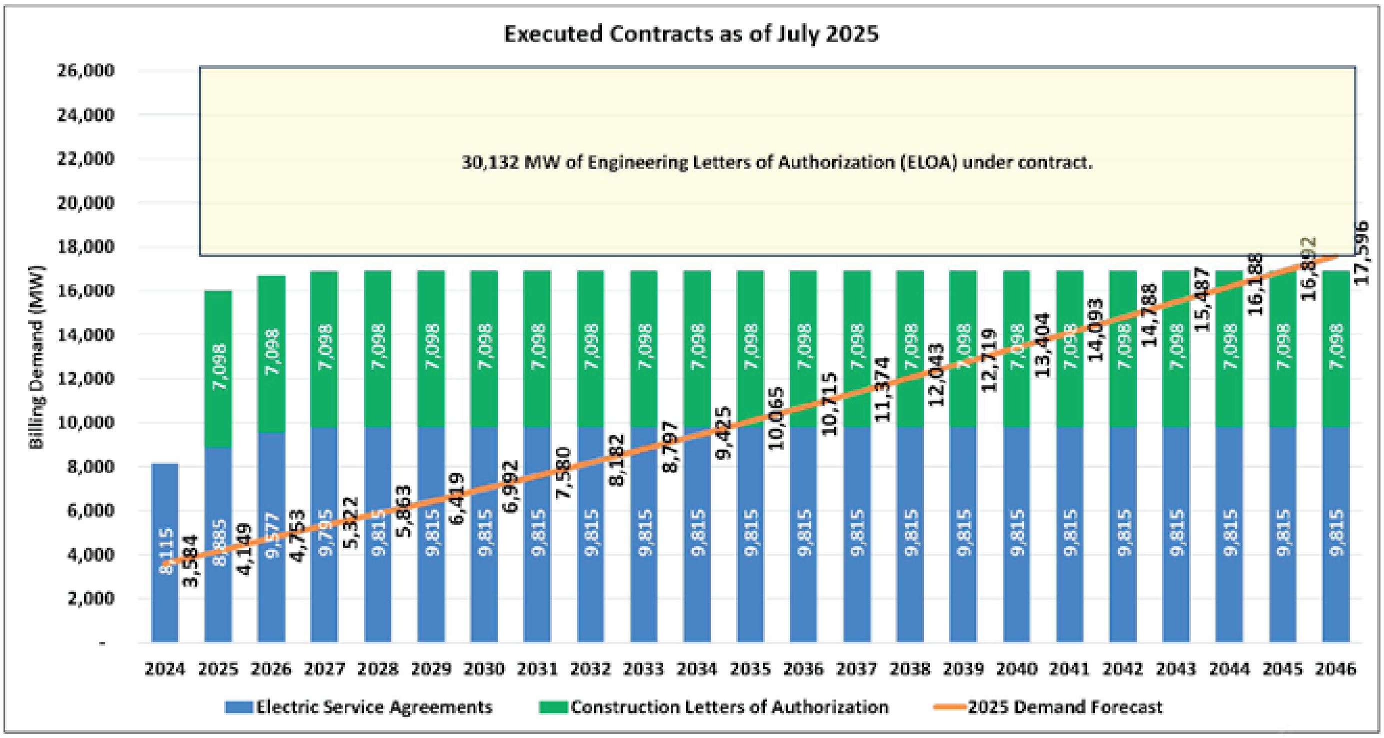
California Energy Commission Data Center Forecast Adjustments

Metric			Mid Project Realization	High Project Realization	
Scenario	**Load Realization**	**Low Project Realization**	**Baseline and Planning**	**Local Reliability**	**Load Ramping/ Energization Date**
Group 1: The project has signed an agreement for electricity service with the local electric utility.	67%	50%	70%	100%	Linear ramp over seven years for projects without ramping information
Group 2: The project has an active application for electricity service with the local electric utility.		—	33%	50%	Same as above, plus project schedules shifted to 2028+
Group 3: The project has made inquiries for electricity service, but has not filed an application for service with the local electric utility.		—	—	10%	

Source: California Energy Commission, 2025 IEPR: Preliminary Data Center Forecast (November 13, 2025) , CEC Docket No. 25-IEPR-03, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=25-IEPR-03; CAISO, Response to Chairman Rosner's Letter Re Large Load Forecasting (October 13, 2025), https://www.ferc.gov/media/caiso-response-chairman-david-rosners-09192025-letter-re-large-load-forecasting-americas. Note that the CEC refers to load realization as "utilization factor" and project realization as "confidence level." Scenario refers to different applications of the load forecast in the CEC and CAISO planning processes.

FIGURE 9

Dominion Energy Virginia 2025 Large Load Forecast



Dominion's 2025 Large Load Forecast compares customer-based statistical projections of billing demand with contracted demand from Construction Letters of Authorization (LOAs) and Electric Service Agreements (ESAs). While the statistical model anticipates large load growth beyond contracted projects, forecast billing demand remains below contracted capacity through the mid-2030s.

Source: Dominion Energy Virginia, 2025 20-Year Data Center Forecast, presentation to PJM Load Analysis Subcommittee (September 16, 2025), p. 10. Available at: https://www.pjm.com/committees-and-groups/subcommittees/las.

also maintains a forecast of contracted demand (based on both LOAs and ESAs). Dominion shifted to a deterministic statistical model after finding that its weighted contracted demand forecast (similar to Archetype 2) yielded overly conservative results. As shown in Figure 9, Dominion's forecast of large load billing demand remains significantly below its forecast of demand from LOAs and ESAs through the mid-2030s.

While Dominion is currently the only utility we are aware of that uses a customer-based statistical model, other utilities may adopt statistical practices when sufficient historical data are accumulated. The increased load evident in Duke Energy and Dominion's approach beyond the mid-2030s could affect the utilities' nearer-term generation and transmission plans as they prepare to serve higher loads later in the planning study period.

Stochastic: Forecast Leverages Probabilities or Distributions Representing Key Parameters

Stochastic (or probabilistic) forecasting explicitly incorporates uncertainty by assigning probabilities or distributions to individual projects and parameters such as project realization, energization dates, ramp schedules, or load realization. While the inputs are similar to those used in deterministic forecasts, stochastic forecasts produce probability-weighted forecasts, showing wider pathways along which load growth may evolve. This also creates an opportunity for more rigorous validation procedures than deterministic models.

The impact on planning outcomes depends on how the forecast is used. For example, a generation or transmission plan designed for nearly all possible futures in a stochastic analysis would likely guarantee service as the customers'

FIGURE 10

Santee Cooper 2024 Load Forecast, Stochastic Analysis of Large Load Growth

Potential Load (MW)	Year 2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
0	100.00%	81.97%	17.97%	1.87%	0.12%	0.01%	0.00%	0.00%	0.00%	0.00%
0 - 100	0.00%	18.03%	43.11%	8.56%	1.05%	0.12%	0.02%	0.01%	0.00%	0.00%
100 - 200	0.00%	0.00%	31.01%	19.01%	4.24%	0.64%	0.15%	0.06%	0.05%	0.03%
200 - 300	0.00%	0.00%	7.40%	26.26%	10.75%	2.24%	0.45%	0.24%	0.14%	0.11%
300 - 400	0.00%	0.00%	0.52%	21.62%	17.71%	5.82%	1.55%	0.72%	0.46%	0.37%
400 - 500	0.00%	0.00%	0.00%	12.53%	20.45%	10.83%	3.50%	1.95%	1.40%	1.18%
500 - 600	0.00%	0.00%	0.00%	7.12%	14.99%	16.28%	6.80%	3.64%	2.63%	2.25%
600 - 700	0.00%	0.00%	0.00%	2.63%	11.59%	15.72%	11.61%	7.27%	5.05%	4.44%
700 - 800	0.00%	0.00%	0.00%	0.40%	9.17%	13.25%	13.73%	11.93%	9.69%	8.33%
800 - 900	0.00%	0.00%	0.00%	0.00%	6.14%	12.70%	12.57%	12.94%	13.37%	12.91%
900 - 1000	0.00%	0.00%	0.00%	0.00%	2.74%	10.45%	12.48%	11.17%	11.29%	12.03%
1000 - 1100	0.00%	0.00%	0.00%	0.00%	0.87%	6.53%	12.79%	12.15%	10.74%	9.99%
1100 - 1200	0.00%	0.00%	0.00%	0.00%	0.17%	3.39%	10.26%	13.25%	13.47%	12.67%
1200 - 1300	0.00%	0.00%	0.00%	0.00%	0.02%	1.46%	6.48%	10.11%	12.43%	13.82%
1300 - 1400	0.00%	0.00%	0.00%	0.00%	0.00%	0.49%	3.70%	5.95%	7.64%	8.54%
1400 - 1500	0.00%	0.00%	0.00%	0.00%	0.00%	0.08%	2.33%	3.99%	4.50%	4.73%
1500 - 1600	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.07%	2.73%	3.62%	3.93%
1600 - 1700	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.40%	1.37%	2.39%	2.96%
1700 - 1800	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.10%	0.44%	0.94%	1.36%
1800 - 1900	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.08%	0.19%	0.31%
1900 - 2000	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%	0.00%	0.01%	0.02%

Santee Cooper's 2024 Large Load Forecast uses stochastic analysis to model uncertainty in project realization, energization date, and load ramping. The figure shows probability-weighted outcomes for cumulative large load growth, illustrating a range of potential trajectories based on simulated variations in project development and timing.

Source: Santee Cooper, presentation to ESIG Large Loads Task Force Forecasting Team (May 2025).

projects and schedule evolves, but at higher cost than a plan that is designed for the middle of the range.

Several utilities, including Georgia Power, NOVEC, and Santee Cooper, use stochastic practices for large load forecasting. These forecasts use Monte Carlo simulations or similar techniques to generate a distribution of outcomes. The stochastic data may be simplified into several scenarios (for example, Georgia Power), or the forecast may utilize the full range of potential loads in its load forecast, as shown for Santee Cooper in Figure 10.

Stochastic forecasting methods require a load forecast to include probabilistic assumptions about possible future outcomes. The usefulness of a stochastic forecast depends on the quality of the input data and probabilities assigned to parameters underlying the forecast model. Without sufficient data, stochastic forecasts may mask the influence of methods for assigning probabilities (e.g., historical realization rates and staff judgment) and introduce false certainty. But if a stochastic forecast is built upon sufficient historical data, it provides more paths to problem-solving than a deterministic forecast.

Regional Load Forecast Practices

Regional load forecasts use many of the same practices as utilities do. But because they often aggregate constituent utility forecasts as a starting point, regional forecasts differ in how they handle adjustments, overlays, and regulatory expectations.

Most RTOs and ISOs prepare long-term regional large load forecasts. The California Energy Commission and Bonneville Power Authority also prepare these forecasts. (The California Energy Commission forecast is used in planning by CAISO, utilities, and the California Public Utilities Commission.) Other organizations, such as the Northwest Power and Conservation Council, prepare regional load forecasts for regional coordination or study purposes. Many regional forecasts offer several future development scenarios rather than a single forecast.

FIGURE 11

Regional Load Forecast Practices

	Post-Hoc Adjustment	Scenario Overlay	Regulatory Approach
	Aggregate member forecasts, then adjust	Aggregate member forecasts, then apply scenario overlays	Direct load-serving entities to use consistent forecasting practices (in progress)
California Energy Commission		✔	✔
Electric Reliability Council of Texas	✔		✔
New York Independent System Operator		✔	
PJM	✔		✔
Southwest Power Pool	✔		

Many regional entities aggregate and adjust utility forecasts, but methodologies vary. This figure compares how different regions align member forecasts, apply adjustments, and incorporate policy-driven or system-level uncertainty. These approaches illustrate how regional harmonization can improve consistency across large load forecasting practices.

Source: Energy Systems Integration Group.

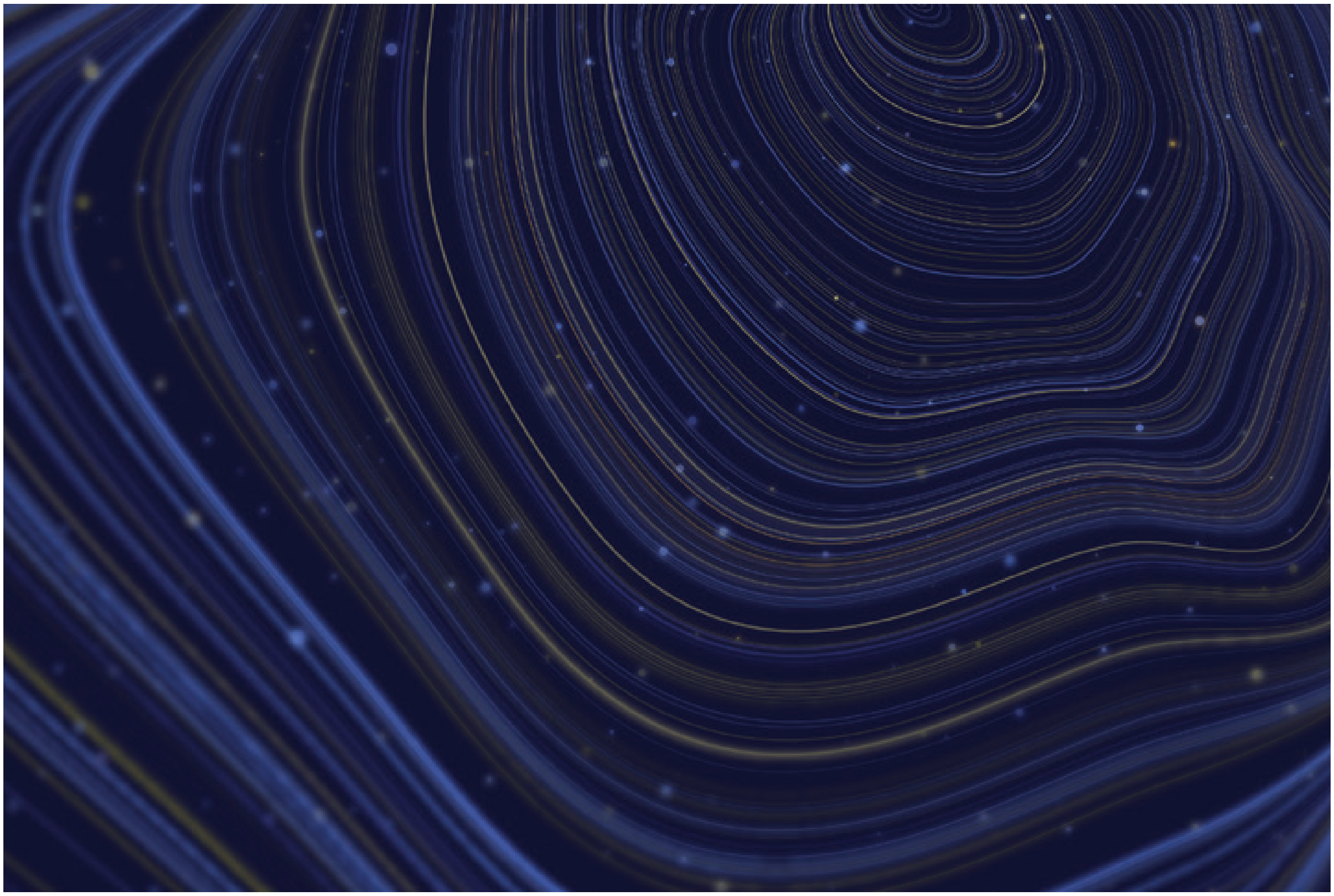
Figure 11 summarizes key variations in how some regional load forecasts aggregate utility forecasts and address policy- or system-level uncertainty by adjusting constituent utility forecasts. Most of these regional forecasts include adjustments intended to align each utility's forecast for greater regional consistency. For instance, in 2025, ERCOT transmission owners submitted an aggregated 117 GW large load forecast for 2030, but ERCOT's adjustments reduced the forecast to 48 GW (ERCOT, 2025b). The California Energy Commission, ERCOT, and PJM have each adopted load forecasting planning standards or practices to regionally harmonize members' forecast practices across each region; this is labeled as a "regulatory approach" in the figure, even though formal regulations have not yet been adopted.

Forecast harmonization may also be required *within* a region. SPP is currently harmonizing its two separate utility-submitted forecasts for resource adequacy and transmission planning (SPP, 2025a). MISO's and the Ontario Independent Electricity System Operator's (IESO's) regional load forecasts take a different approach, using large load forecasts that are more akin to bottom-up forecasts (MISO, 2025).[13] Because regional authorities have less direct access to customer-supplied information, the MISO and IESO forecasts rely more heavily on public announcements, trade association information, and federal government data, in addition to member input. The Independent System Operator New England (ISONE) has had limited experience with large loads to date (ISONE, 2025).

Awareness of Alternative Sites in Other Jurisdictions

Duplicative and, in some cases, speculative large load requests are a widely discussed challenge. It is commonly understood that customers—especially data centers—

13 MISO actually has two load forecasting processes. MISO states that, "for the load forecasts used in the [planning resource auction] and transmission planning reliability studies, MISO relies on its members to apply screening criteria. [Expedited project review] requests submitted to MISO are based on the expectation that the large load requests have been vetted by the members to identify and understand the local transmission needs as outlined in MISO's [expedited project review] request form." Alternatively, "for the Long-Term Load Forecast, MISO evaluates prospective large loads for inclusion using several sources of information, including: (1) publicly available data on announced data center developments, and (2) commercially available data on new data center developments obtained from third-party monitoring services (such as LandGate) . . . ." (MISO, 2025).



often explore multiple siting options across jurisdictions. However, utilities typically lack clear visibility into whether a given project is part of an applicant's broader site comparison effort. Most load forecasts do not appear to directly evaluate the likelihood that specific projects will end up locating elsewhere, but rather use a project realization rate to reflect overall cancellation rates.

Efforts to determine whether alternative sites are under consideration are increasing:

- Texas Senate Bill 6, passed in 2025, requires disclosure of applicants' alternative sites within Texas (Texas Legislature, 2025).
- Santee Cooper asks customers whether they are considering alternative sites and incorporates the data as part of its project realization scoring.
- MISO 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.
- PJM has proposed requiring that utility submissions of large load forecast adjustments include customer-provided information regarding "duplicative" interconnection requests (PJM, 2025a).

The most detailed proposal for obtaining and reviewing alternative site information is in the staff discussion draft for new Large Load Interconnection Standards for ERCOT (PUCT, 2025).

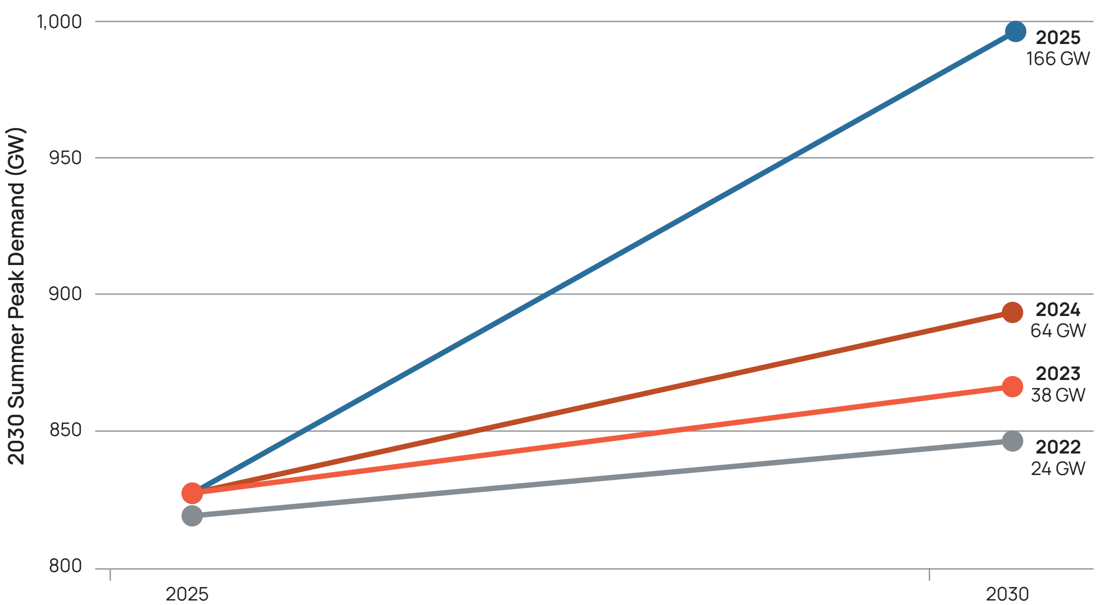
2025 National Load Forecast

Due to new large load requests, the total national five-year (2025-2030) load growth forecast according to Grid Strategies' analysis is now 166 GW, representing 20% of current peak load demand (see Figure 12). This national estimate is based on an aggregation of utility and regional load forecasts submitted to FERC, as well as more recent published updates. Compared to just three years ago, forecast growth for the same five-year period has increased from 24 GW (2.9%) in 2022, a six-fold increase.

Load forecast updates are issued throughout the year. In addition to data filed with FERC, the 166 GW forecast compiled by Grid Strategies includes a recent update by SPP. PJM plans to release an update later in 2025, mostly driven by data center load requests (PJM, 2025b). PacifiCorp is seeing high data center load growth but now excludes that load from its official system planning forecast (PacifiCorp, 2025).

FIGURE 12

Total National Peak Demand Growth Forecast for 2025–2030 (Forecasts from 2022–2025)



Aggregated utility and regional forecasts of peak demand growth between 2025 and 2030 have risen sharply in recent years, from about 24 GW in 2022 to 166 GW in 2025, reflecting the rapid emergence of new large load requests. Although aggregate national load forecasts are not used for grid planning, they provide valuable context for trends shaping utility and regional planning efforts nationwide.

Source: Wilson et al. (2025), *Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers* (November 2025), Grid Strategies, https://gridstrategiesllc.com/project/load-growth-forecast/.

TABLE 4

Planning Areas with Highest Peak Load Growth (2025–2030)

	2025 Peak Load Forecast (GW)		Five-Year Forecast Growth	
	2025	2030	(GW)	Percent
ERCOT	85.8	138.9	53.2	62%
PJM	154.1	183.9	29.7	19%
SPP	57.9	82.0	24.2	42%
MISO	130.0	145.5	15.6	12%
Georgia Power	17.8	25.8	8.0	45%
CAISO	46.1	52.9	6.8	15%
Duke Energy (Carolinas)	34.1	37.5	3.4	10%
Salt River Project	8.5	11.3	2.8	33%
PacifiCorp	14.3	16.3	2.0	14%
Florida Power & Light	26.3	27.9	1.6	6%
All other planning areas	253.9	273.1	19.2	8%
Total	**828.8**	**995.3**	**166.5**	**20%**

Source: Wilson et al. (2025), *Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers* (November 2025), Grid Strategies, https://gridstrategiesllc.com/project/load-growth-forecast/.

Nearly three-quarters of the 166 GW in forecast peak load growth comes from the four largest load forecast regions in the country: ERCOT, PJM, SPP, and MISO, according to the Grid Strategies analysis summarized in Table 4. Seven other regions comprise most of the rest of the growth.

Another way to understand forecast load growth is by summarizing utility energy forecast data submitted in integrated resource planning proceedings. RMI collected energy forecast information from 130 resource plans, covering approximately 48% of electric load, as shown in Figure 13 (p. 29). The 24% electric energy growth rate should not be directly compared to the 20% peak demand growth rate shown in Table 4, because it covers a longer analysis period (10 years vs. 5 years) and measures electricity use (GWh) rather than summer peak load (GW).

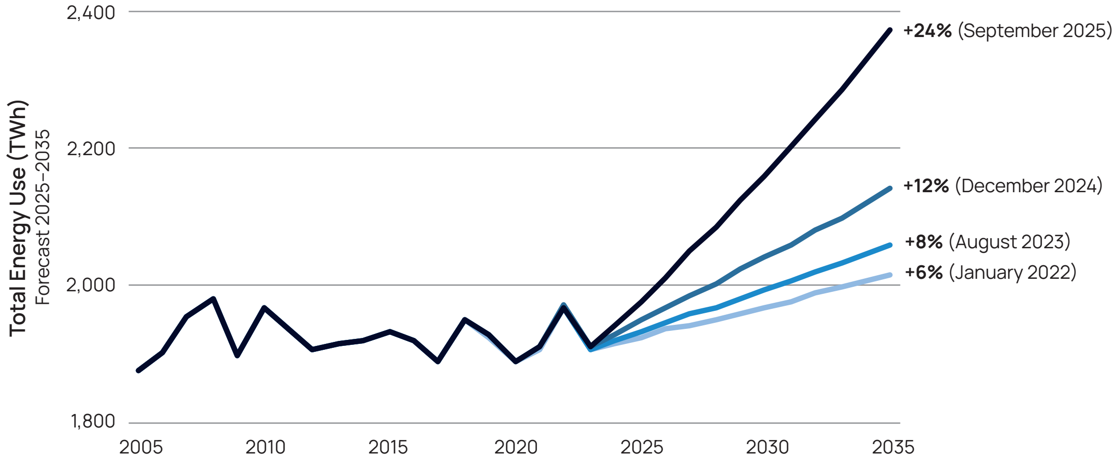
Drivers of Load Growth

Over the next five years, load forecasts indicate that the main drivers of growth are expected to be investment in data centers and industrial/manufacturing factories, as shown in Figure 14 (p. 29). Smaller shares include oil and gas/mining and "other"—where "other" includes some large loads but mostly growth in smaller customer loads, including residential and small commercial. As discussed in the subsection "Load Differentiation" above, load forecasts have not adopted standardized definitions for categories of large loads and often do not report detailed data. Accordingly, Grid Strategies' analysis of utility load forecasts required its authors to apply significant professional judgment to interpret and apply available data to estimate a breakdown of forecast load growth by sector.[14]

14 The load growth breakdown between data center, industrial, and other loads is based on Grid Strategies' analysis of numerous utility and planning area forecast documents. Information obtained from those documents was used to apportion the respective forecast load growth into categories for 2025.

FIGURE 13

Actual and Projected Energy Use in Utility Plans (2005–2035)

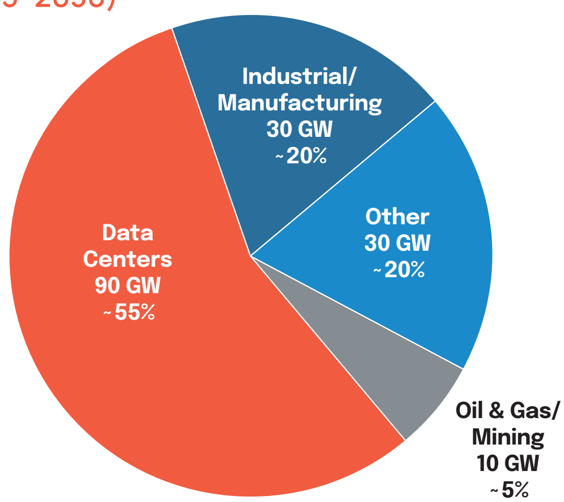


Analysis of integrated resource plans shows significant growth in total electricity use through 2035. This graph shows how greatly projected electric energy demand has increased between the 2022 forecast (lowest line on the right) and the September 2025 growth forecast (top line). The 24% energy growth rate shown here represents projected consumption (GWh) in utility plans covering roughly half of U.S. load. Although not directly comparable to peak-demand forecasts, these data highlight the sustained rise in systemwide electric energy requirements.

Source: RMI, Engage and Act (data accessed October 2025). https://rmi.org/our-work/climate-finance/engage-and-act/.

FIGURE 14

Grid Strategies' Estimate of Load Growth Drivers (2025–2030)



Analysis of utility and planning area forecast documents indicates that most expected U.S. load growth between 2025 and 2030 can be attributed to data centers, followed by industrial and manufacturing projects. Smaller shares are linked to oil and gas, mining, and other customer classes, including residential and commercial electrification.

Source: Wilson et al. (2025), *Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers* (November 2025), Grid Strategies, https://gridstrategiesllc.com/project/load-growth-forecast/.

Over the next five years, load forecasts indicate that the main drivers of growth are expected to be investment in data centers and industrial/manufacturing factories, with smalller shares of oil and gas, mining, and small customer loads, including residential and small commercial.

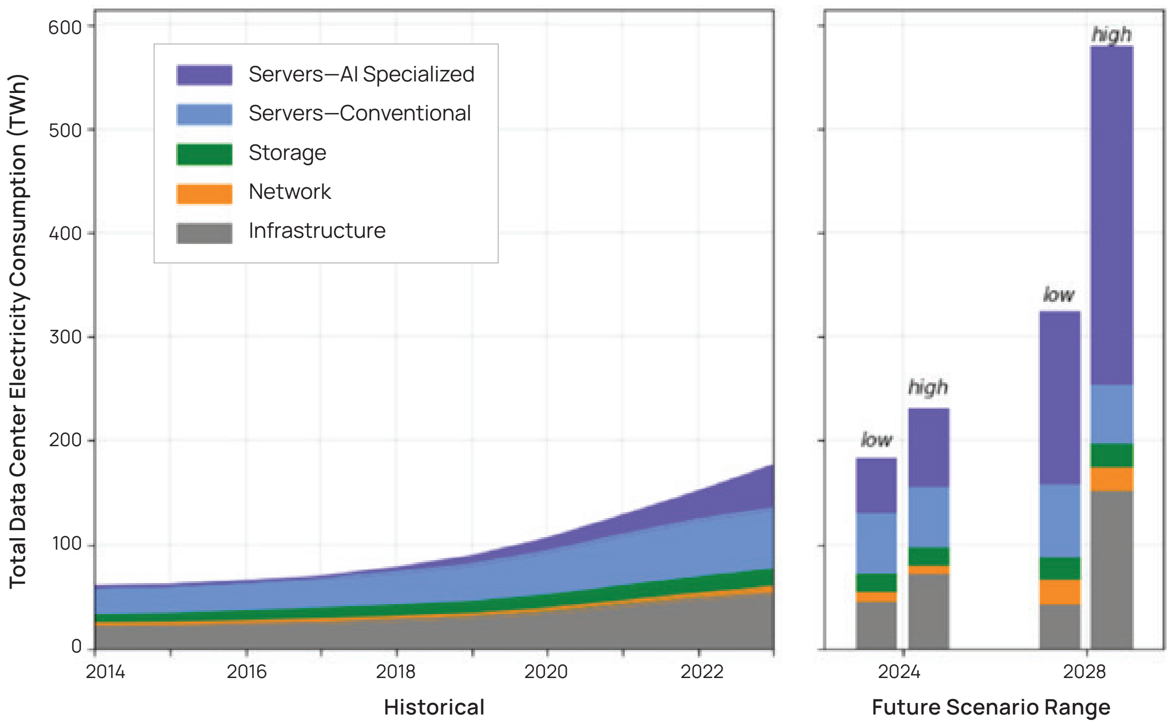
Data Centers

According to this analysis of utility load forecasts, of the 166 GW of forecasted load growth for 2030, roughly 90 GW are linked to data centers. Very few load forecasts differentiate between types of data centers. While some break out crypto mining facility load, not enough do so to provide a useful national estimate for this subcategory. Notably, load from AI projects (the largest set of new large load projects) is not explicitly tracked in any publicly available load forecast.

The potential to reach 90 GW of new data center demand is supported by a bottom-up analysis of data center server

FIGURE 15

LBNL's 2024 Estimate of Energy Use by Data Centers (2014-2028)



The Lawrence Berkeley National Laboratory's analysis projects total U.S. data center electricity demand rising from roughly 50 TWh in 2014 to 325-580 TWh by 2028. The growth is driven primarily by AI-specialized servers. These projections offer a bottom-up benchmark based on historical trend extrapolation without accounting for supply chain limits or other influencing factors.

Source: Shehabi, A. et al., 2024 United States Data Center Energy Usage Report (December 2024), LBNL-2001637, p. 53, https://eta.lbl.gov/publications/2024-lbnl-data-center-energy-usage-report. © The Regents of the University of California, Lawrence Berkeley National Laboratory.

shipments by the Lawrence Berkeley National Laboratory (LBNL). This analysis found that total power demand for data centers could reach between 74 and 132 GW in 2028, or 325 to 580 TWh of energy use, as shown in Figure 15. Notably, this growth through 2028 is driven primarily by AI-specialized servers, which consume more energy per processor, even though they represent just a fraction of the processors installed in data centers (Shehabi et al., 2024). The LBNL analysis extrapolates historical trends and does not consider supply chain (e.g., semiconductor availability) constraints, utility forecasts, or data center industry investment reports.

Grid Strategies compared the aggregate national forecast estimate of 90 GW in forecast data center load with three alternative benchmarks:

- Cleanview is tracking about 60 GW of data centers scheduled to begin operation before 2029 (but may not track all projects) (Cleanview, 2025).
- In mid-2024, based on anticipated shipments of processing chips for data centers, TD Cowen projected 65 GW of new power demand by 2030 (Elias et al., 2024).
- Other data center market analysts use utility-published data and information from data center developers to forecast data center and large load growth. Despite significant variations on scope and methods, all point to growth well below 90 GW (Wilson et al., 2025).

Based on this comparison, Grid Strategies concluded that the 90 GW data center load growth forecast is likely to be overstated by roughly 25 GW on a national basis.

Industrial, Manufacturing, Oil and Gas, and Mining Sectors

The Grid Strategies analysis finds that industrial and manufacturing drives about 30 GW of five-year load growth,

with oil and gas and mining sectors contributing perhaps 10 GW more. While load forecasts often provide detail for subsectors, inconsistent subsector definitions and reporting make further detail impractical.

Other Sources of Load Growth

Other sources of load growth, including residential and commercial uses (including building and transportation electrification), could contribute another 30 GW (Wilson et al., 2025). Some of this load may be reported as residential and commercial growth, but other load may not be specifically classified. Many load forecasts had roughly zero growth for other load classifications, while in some other load forecasts, as much as half of load growth is attributed to these factors collectively.

Challenges to Constructing a Unified National Large Load Forecast

While some benchmarking of the aggregate national large load forecast is possible, it is difficult to judge whether the national load forecast is reasonable and how to improve it. The project team explored the question of whether some national organization, such as a national laboratory (e.g., LBNL) or a major industry research organization (e.g., EPRI) might be able to construct a unified national large load forecast using consistent, transparent methods to assist utilities in benchmarking and improving their forecasts. The discussion identified substantial obstacles to such an effort:

- Reconciling customers' announced data center goals with load interconnection requests requires substantial information that only utilities have.
- Even utilities may not know the ultimate customer(s) of proposed projects.
- It is practically infeasible to execute non-disclosure agreements with utilities and regional planning authorities to obtain data about customers.
- Energy analysts are "ill-equipped" to model data center energy demand due to "critical data gaps and the fast-moving nature of AI technology" (Masanet et al., 2024). While industry specialists use investment data and chip shipments to forecast near-term growth, there may be questions about whether their data are comprehensive and accurate.

The project team concluded that it will be very difficult to align utility-sourced load forecasts with independent national-scale expectations about data center load growth. This topic is further explored in the section "Developing New Information Resources and Forecasting Practices," where the project team recommends building a database of load forecast metric data. The discrepancy between the national large load forecast and industry specialists' forecasts may shrink (or grow), but it may not be possible to effectively align utility, regional, and national large load forecasts.

Using Available Data to Improve Forecast Accuracy

The project team has identified a number of practices that can be used for large load forecasts to make the best use of information that is available now or likely to soon become available. Many of these practices were discussed in the section "Large Load Forecasting Practices Today." They can be incorporated into utility and regional load forecasts if data availability allows. Some techniques are already well established while others are in advanced stages of development.

Today, the most pressing problem facing load forecasts is arguably that data center load is forecast at an unrealistic level, at least for the next five years. As discussed in the section "2025 National Load Forecast," the data center portion of utility and regional load forecasts may be 25 GW higher than alternative benchmark forecasts. As discussed in "Large Load Forecasting Practices Today," individual utility or regional data center load forecasts will find it challenging to correctly anticipate their "share" of the potential buildout of data center power demand on a nation-wide basis due to uncertainty in key load forecast metrics.

- **Project and load realization**: Some data center interconnection requests may represent "double counting" in that data center developers may pursue projects in multiple utility territories due to uncertainty regarding the feasibility or schedule for load interconnection. There are also speculative requests from developers that do not yet have final customers. Load realization may be affected by business strategy or project design advances. For example, efficiencies in project design may only reach sufficient maturity late in the project development process.
- **Energization date and load ramping**: Data center interconnection requests may be based on over-optimistic delivery schedules for key data center components, such as servers. Even if the customer accurately forecasts actual demand, the ramp rate to that level of demand may be slower than expected.

Given that potential data center forecast error drivers appear to be correlated (as with duplicative project requests and common dependence on tight supply chains), relatively small errors in each utility load forecast may yield a large cumulative forecast error. There is no guarantee that the errors will be distributed uniformly across utilities—some utilities may get it right and others miss due to market forces that could not be reasonably anticipated by any one utility.

Below, the project team reviews the first seven recommendations discussed in the executive summary and suggests ways that utilities may implement continuous improvement practices through forecast validation studies.

FIGURE 16

Five Large Load Characteristics and Forecast Metrics

Project Realization	Energization Date	Load Realization	Load Ramping	Load Factor or Load Shape
The rate at which projects included in the load forecast are placed in service • Often presented as a percentage of project requests expected to come to fruition	The beginning of commercial operation by projects, including anticipated delays	The forecast peak load that the project is expected to require once it's fully scaled up • Often presented as a percentage of requested peak load	The monthly or annual forecast of demand during the startup period of commercial operation • Often presented as a percentage of requested peak load	• Load factor: Actual energy use as a proportion of facility capacity • Load shape: More detailed information on power needs, for example, an hourly schedule of energy use

Large load forecasts can characterize and evaluate new loads using five core metrics: project realization, energization date, load realization, load ramping, and load factor/load shape. Together, these describe whether, when, and how completely large load projects materialize and how they use electricity over time. Applying these metrics consistently improves comparability and transparency across forecasts.

Source: Energy Systems Integration Group.

Recommendation 1: Use All Five Large Load Metrics to Create a Large Load Forecast

As discussed in the section "2025 National Load Forecast," the large load forecast represents the vast majority of load growth in many load forecasts. Just a few years ago, load forecasting practices were generally well understood and not particularly controversial. But today, scrutiny of large load forecast practices is justifiable due to their novelty and importance.

A well-structured large load forecast clearly describes, collects applicant data for, and implements the five large load metrics in Figure 16 to characterize and weight information about large loads used to construct the large load forecast.

These concepts are embodied in most, if not all, large load forecasts—but in ways that are inconsistent or lack transparency in many instances. For example, large load forecasts often combine the concepts of project realization and load realization into a single adjustment factor. For instance, if the project pipeline includes 1,500 MW of large load projects, the forecast might state that it expects only 500 MW to be realized, without specifying what combination of project realization and load realization rates were used to calculate this result. Another area for improving clarity is how large load customers will use on-site generation and how that will affect load realization, load ramping, and load factor or load shape.

Instead of combining multiple concepts into a single result, individual weighting factors for each load forecast metric could improve clarity and result in a better load forecast. Development of each weighting factor could be informed by a maturity assessment, ideally as described in Recommendation 9. As noted by FERC Chairman Rosner, criteria used to assess the "commercial readiness of large projects in the *generator* interconnection queue . . . include[ing] observable milestones such as contracts, financial security deposits, and physical site control" could be a model for assessing the maturity of load interconnection requests (FERC, 2025a). Such a process could include thresholds for considering or excluding project information in load forecast development—projects that do not meet certain project maturity thresholds may not be considered in the load forecast.

Adopting clear metrics for large load forecasting is a precondition to some practices discussed in sections "Using Available Data to Improve Forecast Accuracy" and "Developing New Information Resources and Forecasting Practices" of this report. These lay the foundation for developing new metrics, such as for load flexibility, as discussed in "Developing New Information Resources and Forecasting Practices."

Recommendation 2: Develop a Consistent Framework to Differentiate Among Large Load Types

A large load classification system can consistently identify large load types (including facility business purpose, size, and load shape) across forecasts. Each load forecasting authority calibrates its load forecasting practices to reflect the unique characteristics and planning requirements in its service territory or region. This concept can be extended to consider technological variety among large loads—as different technologies exhibit distinct consumption patterns, ramp rates, and operational behaviors—to improve their forecast. As discussed in the section "Large Load Forecasting Practices Today," load forecasts do not currently share a consistent language of large load types or share practices regarding how to treat technology differences.

While many load forecasts differentiate large load forecasts based on different large load types, the details of these practices are not transparent, and appear to vary widely. In contrast, load forecasts for other loads use transparent and generally consistent definitions of residential, commercial, and other classifications of load. As large load forecasting practices are at an early stage, variation is to be expected, but could become an obstacle to industry-wide learning and improvement.

Industry could develop, or converge upon, a consistent set of detailed large load types and classifications. The types would group customers with similar load forecast metrics as well as common characteristics such as size, business model, and site climate conditions. This would simplify categorization of new customer interconnection requests and allow consistent identification of load types across utility and regional footprints and forecasts.

To implement this approach, load forecasts will need sufficient customer data to enable categorization of new large load interconnection applications. The project team learned that some utilities do not have confidence that internal data fully identify and classify large load customers by type, both within their customer base and among

Industry could develop a consistent set of detailed large load types and classifications, grouping customers with similar load forecast metrics as well as common characteristics such as size, business model, and site climate conditions. This would simplify categorization of new customer interconnection requests and allow consistent identification of load types across utility and regional footprints and forecasts.

customers requesting service. Where this information is lacking, it complicates the application of type-specific forecasting models. To obtain and manage customer data by load type, utilities will need to invest in customer research and new requirements for data submission by prospective new customers.

Given large load categories and interconnection project data, utilities could develop forecasting frameworks with modeling and validation practices that use similar data and methods for load types with historical experience and predictability of outcomes. Each type of customer could be forecast using its own specific parameters, inputs, or assumptions, but there should be a common practice of specifying the data sources and methods used to generate each load forecast metric.

If a utility's data center load forecasting is at an early stage of development due to a lack of historical data about project realization, load ramping, etc., the utility could use a contract-only deterministic forecast method (see "Large Load Forecasting Practices Today," Archetype 1) for data centers as best suited for forecasting a technology type with low information availability. That same load forecast might recognize vehicle manufacturing as a well-understood, expanding load sector and choose to use an extended-forecast method (see "Large Load Forecasting Practices Today," Archetype 3). Balancing methodological consistency with a recognition of varying data certainty and granularity is a practical approach to capturing emerging large-load technology load characteristics.

Adopting such a framework would also allow a large load forecast to explicitly recognize the uncertainty associated with the contributions of each load type. This could be reflected in weighting factors, stochastic modeling, or scenario development.

While the project team did not identify any large load forecast that has transparently adopted such a unified forecasting framework, it did see evidence that some utilities differentiate modeling practices between, for example, data centers and manufacturing facilities. But none of the load forecasts reviewed for this report made such assumptions or historical data publicly available, and no U.S. research organization has yet shared models for how to forecast different large loads' future demand and operational behavior. In addition to adopting a unified forecasting framework, we discuss the need for collaboration and data sharing to further improve forecast accuracy in Recommendation 8, found in the section "Developing New Information Resources and Forecasting Practices."

Recommendation 3: Account for Uncertainty

Optimal planning of transmission and generation investments means accounting for uncertainty in both front-end and back-end risk. Front-end risks refer to uncertainty in the quantity and timing of infrastructure needed to serve new loads. Some of the drivers of front-end risk include

computing supply chain disruptions, an inability of the electricity industry to build out enough transmission and energy supply to serve data center and other large load demand, regulatory changes, and major improvements in computational efficiency. To address these risks, large load forecasts are often structured around thresholds for project inclusion and weighting of project realization, load realization, and other load metrics to predict outcomes consistent with historical experience, using professional judgment.

Large load forecast practices are evolving rapidly to deal with front-end risk and have adopted practices to account for uncertainty that include:

- **Weighting factors:** Applying adjustments that acknowledge that not all projects reach 100% achievement of customer's projected level of service
- **Stochastic modeling:** Considering varying probabilities for contract and proposed projects as to the level of service achieved, by year
- **Scenario-based forecasts:** Considering several alternative sets of assumptions or weighting factors to develop a discrete number of scenarios for planning studies

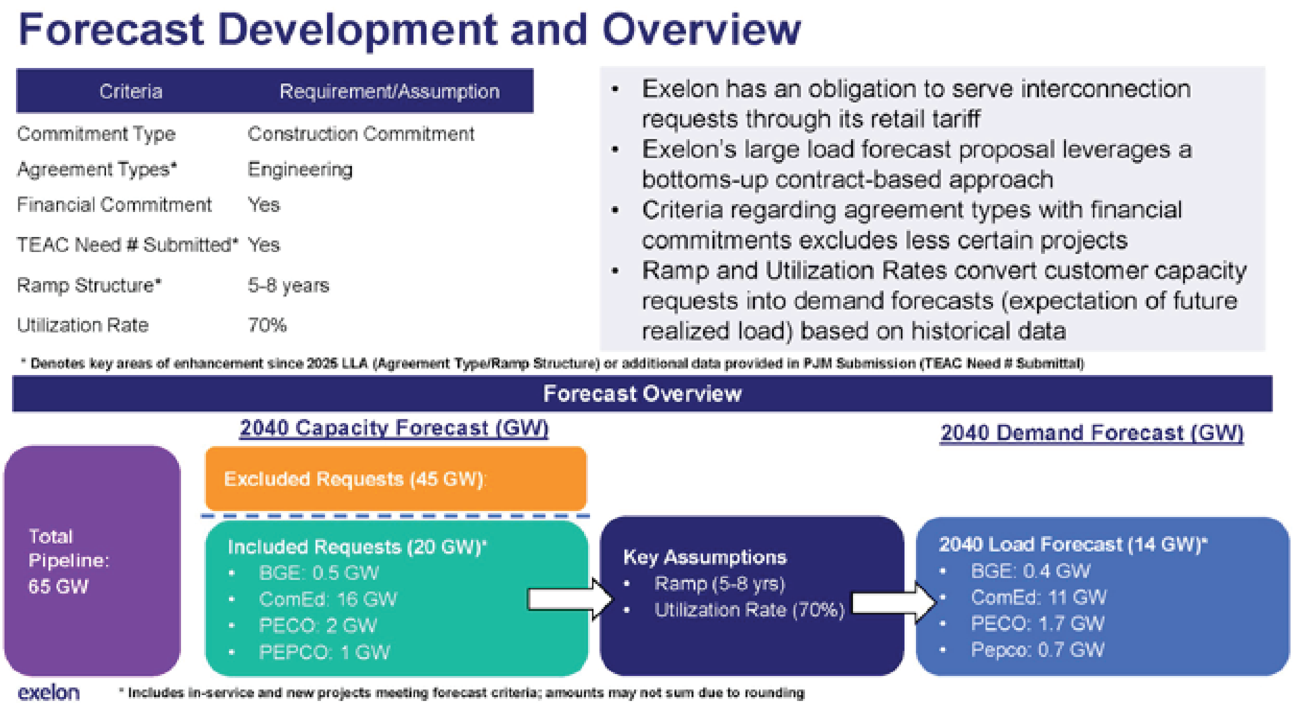
Back-end risks center on whether the infrastructure and investments built to serve new loads will remain used and useful over their lifetimes. However, many large load forecasts do not currently address back-end risks and overlook attrition or systemic risk of customers reducing or cancelling service, which could lead to inefficient or excessive utility or regional infrastructure investments. If such risks are correlated across a substantial share of system load, then methods for evaluating this systemic risk can be included in transmission and resource planning.

Weighting Factors

Weighting factors address the inherent uncertainty in large load development by overriding the assumption that all proposed projects will achieve their full projected level of service. Weighting factors may be informed by historical realization rates for large loads in general, for specific customer types, or for the customer's historical data from other facilities in the utility's service territory. For example,

FIGURE 17

Exelon Large Load Forecast Overview



Exelon converts its pipeline of contracted projects into expected demand by applying weighting factors for project realization, load ramping, and utilization. This slide illustrates how these adjustments reduce the total pipeline to a more probable forecast of peak demand, emphasizing the role of historical data and financial commitment criteria in refining large load projections.

Source: Exelon, Exelon Large Load Adjustment Proposal – 2026 PJM Load Forecast (September 16, 2025), presentation to PJM Load Analysis Subcommittee, p. 4. https://www.pjm.com/committees-and-groups/subcommittees/las.

Exelon uses historical data to turn its total load application pipeline into a 2040 demand forecast by adjusting ramp and demand realization (utilization) rates, as shown in Figure 17.

Where professional judgment is used to adjust weighting factors, subject-matter experts or committees may consider the project's overall maturity as reflected in the comprehensiveness of data supplied for its interconnection application, its contractual and permitting status, and other risk indicators. For example, Salt River Project adjusts customer load ramps and demand realization using a project-specific "maturity score" factor. This factor is based on internal and external information in five categories: energy infrastructure, client construction, development permits, land acquisition, and other information.

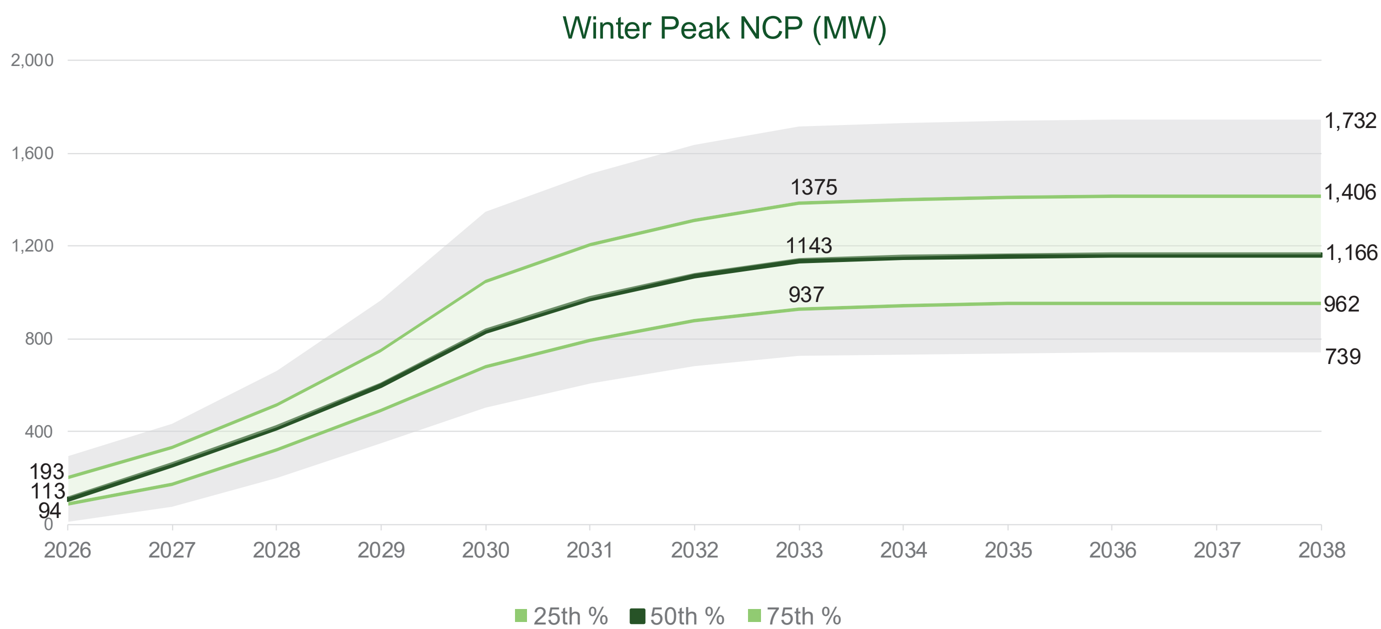
Data center operators have objected to the use of weighting factors in load forecasts. In a detailed complaint about Silicon Valley Power's facility-specific load forecast, STACK Infrastructure argues that its fully constructed facility is "vastly underserved" and unable to be fully leased because the utility's planning documents, based on applied weighting factors, indicated long-term facility energization significantly below the developer's requested capacity (STACK Infrastructure, 2025).

Stochastic Modeling

Stochastic modeling incorporates probabilistic analysis to represent uncertainty and is identified as large load forecasting Archetype 4 in the section "Large Load Forecasting Practices Today." Utilities use stochastic modeling for estimating generation resource plan and

FIGURE 18

Santee Cooper: 2024 Large Load Growth Forecast



Santee Cooper's forecast models uncertainty using stochastic methods that assign probability distributions to key metrics rather than single-point estimates. The figure shows a range of simulated load-growth trajectories generated from varying assumptions for project realization, load realization, and other forecast parameters.

Source: Santee Cooper, presentation to ESIG Large Loads Task Force Forecasting Team (May 2025).

capital project costs and contingencies. As a general rule, stochastic modeling requires a stronger historical or evidence basis for the ranges of input data used in the model than a simpler weighted, deterministic approach.

A stochastic model will ideally consider our five load forecast metrics. But instead of picking a single weighting factor for each metric and project (or group of projects), the stochastic model requires a probability distribution of potential weighting factors. Stochastic models generate a spectrum of load scenarios rather than a single line forecast. This is illustrated in Santee Cooper's 2024 large load growth forecast, as shown in Figure 18.

In the context of large load forecasting, a significant concern is that even utilities with a few years of service data for large load customers lack sufficient historical data to model the most important parameters using stochastic analysis. In the field of cost estimation, advanced parametric modeling methods are most useful when "systemic (i.e., not project-specific) risks such as the level of scope definition are dominant (AACE International, 2008), and stochastic (Monte Carlo) methods are preferred when it is feasible to estimate risk probabilities and especially when correlations between risks can be considered in the model (AACE International, 2012). Those conditions are also likely to identify where stochastic analyses can be an efficient path for creating planning scenario cases.

Utilities use stochastic modeling for estimating generation resource plan and capital project costs and contingencies. As a general rule, stochastic modeling requires a stronger historical or evidence basis for the ranges of input data used in the model than a simpler weighted, deterministic approach.

Scenario-Based Forecasts

Scenarios are a familiar tool in power industry planning and are beginning to be applied to large load forecasts, whether based on deterministic or stochastic analysis. Scenario-based forecasting is particularly valuable for long-term planning studies such as transmission expansion and resource adequacy assessments, where the consequences of under- or over-building infrastructure can be significant.

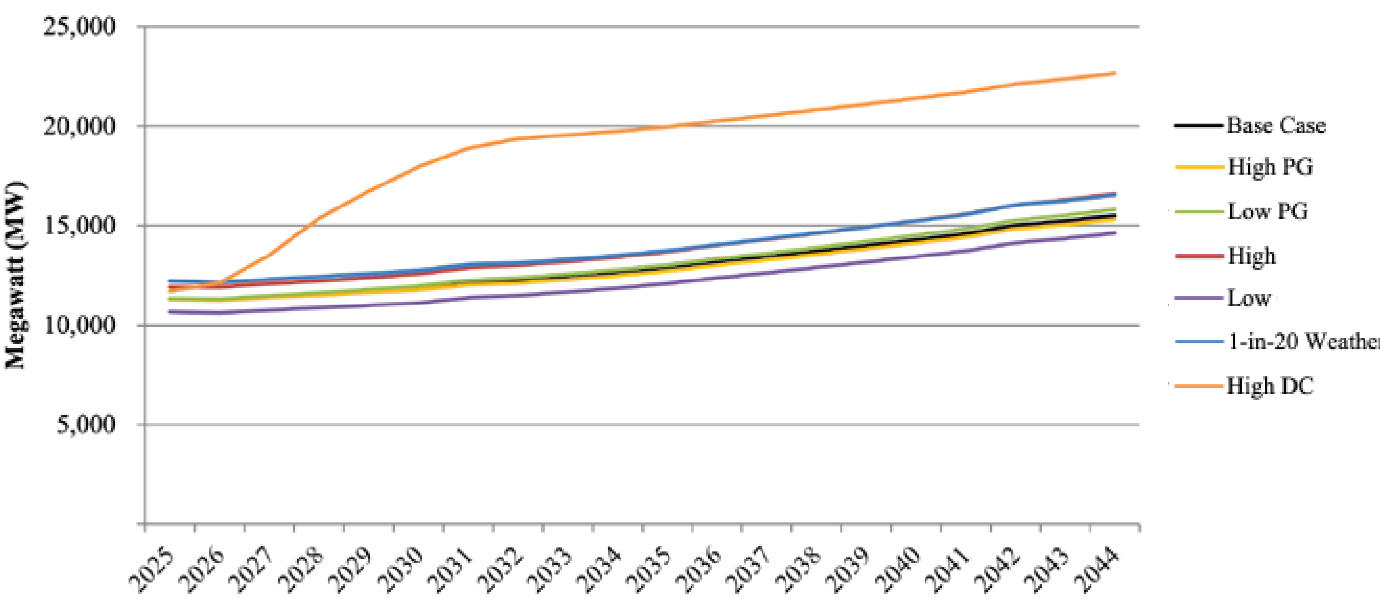
By comparing results across scenarios, utilities can identify robust infrastructure development strategies that perform well under multiple conditions and reduce exposure to planning errors. For example, as shown in Figure 19, PacifiCorp has a high data center load scenario that departs markedly from other scenarios that consider variations in economic drivers, private generation, and weather conditions.

Scenario-based forecasting is particularly valuable for long-term planning studies such as transmission expansion and resource adequacy assessments, where the consequences of under- or over-building infrastructure can be significant.

Typically, either the weighting factor method or the stochastic modeling method would be used to create alternative scenarios by varying the input factors consistent with professional judgment or historical evidence. Simpler approaches are used as well: MISO's low, base, and high data center load forecasts use compound annual adjusted growth rates of 13%, 14%, and 15%, respectively.

FIGURE 19

PacifiCorp Load Forecast Scenarios (Excluding Energy Efficiency Adjustments)



Peak demand forecasts from PacifiCorp's 2025 integrated resource plan. The forecasts shown include a Base Case and several sensitivities, including High and Low economic growth, High and Low private generation (PG) or distributed energy resources, more-extreme weather conditions (1-in-20 Weather), and a High data center (DC) case. The High DC forecast is markedly higher than the other forecasts.

Source: PacifiCorp, 2025 Integrated Resource Plan (March 31, 2025), Volume II, Appendix A, p. 18, https://www.pacificorp.com/energy/integrated-resource-plan.html.

Scenario forecasts can consider futures that would probably not be studied in a stochastic model. For example, scenarios could represent shifts in the mix of large load technologies (more manufacturing, fewer data centers), changes in behind-the-meter generation, or a slowing of future data center additions after the current wave of investments. Policy drivers, global competition, and other relevant factors could also be explored in a large load scenario, although the project team did not identify any such cases.

Addressing Back-End Risk

Once large loads are placed in service and reach full demand, load risk shifts to back-end risks: attrition and systemic risk. The load forecast will include a projection of how long large load customers remain in operation and how, if at all, their load requirements and load shapes will change over time. The project team did not see any load forecasts that considered any alternative to ongoing, continuous, and stable operation by customers after reaching full load.

The challenge of attrition and systemic risk is particularly relevant in the context of the rapid data center industry expansion, and potentially for other types of large load growth as well.[15] Most segments of the data center industry are experiencing aggressive growth, amplifying exposure to correlated risks. Roughly half of today's planned large loads are at a gigawatt scale, with complex development timelines and high dependency on external factors.

Back-end risks include the question of whether current growth projections—driven largely by AI and cloud computing—represent a sustainable trend or a bubble with cancellation of new projects and declining demand for existing projects. The societal costs and losses of building infrastructure to serve these large loads could be significant if project attrition rates are high and utility system investments are not fully utilized over their lifetime. If, after reaching forecast peaks, demand from data centers falls below expectations, utilities could be left with stranded transmission and generation investments. This is one reason that regulators and utilities are proposing new cost allocation, ring-fencing, and revenue recovery methods to protect non-data center customers from data center infrastructure costs.

15 For example, recent changes in federal policy are likely to reduce forecast demand related to hydrogen production.

Because attrition rates for novel technologies and other systemic risks are highly situational and lack historical precedent,[16] it will be challenging to assign meaningful probabilities to attrition risk. Consequently, incorporating systemic risk analysis into scenario planning is a practical approach for evaluating the resilience of long-term infrastructure investments from the perspectives of transmission reliability, resource adequacy, and financial concerns. Utilities and regional planning authorities need to try to design infrastructure plans that can survive or adapt to high-impact, low-predictability market outcomes like the potential large load attrition described above.

A related question is whether future load growth in the transportation and building sectors could soak up overbuilt infrastructure originally intended to serve large load customers. In general, large loads are increasingly planned for suburban or even rural locations with inexpensive electricity and available transmission capacity (BloombergNEF, 2025); grid infrastructure buildout in these locations may not match the requirements of distributed load growth in urban load centers.

Recommendation 4: Increase Certainty Through Large Load Financial Requirements

While the use of weighting factors and other practices can better reflect uncertainty in large load forecasts, it is even more desirable to actively increase certainty.

Tariff, Contractual, and Regulatory Measures

To date, the main method used by many utilities and regulators to reduce near-term forecast uncertainty and back-end financial risk is to modify tariff and contract with new financial requirements for large loads.[17] While this is not a load forecasting practice per se, some proponents for these changes argue that such requirements will reduce uncertainty by increasing project commitment and clarifying the timing, magnitude, and profile of large load additions. This result would reduce the uncertainty of large load forecasts.

The modifications to tariff and contracts for large loads adapt generation interconnection practices to reduce the complexity that high volumes of generation interconnection requests place on technical study needs and queue management. For large loads, stricter terms, including higher financial requirements and limitations on contract modifications or exit are expected to discipline customer inquiries and progression through the load interconnection process. This should reduce the risk of stranded costs due to under-utilized investments and reduce the magnitude of exaggerated large load forecasts. For example, after approval of its new data center tariff rate schedule, with enhanced financial commitments and other requirements, AEP Ohio reported that its load interconnection request pipeline for data centers dropped by about 57%, from 30 GW to 13 GW (AEP, 2025; PUCO, 2025).

Stricter tariff and contract elements can be used to verify the viability of prospective new customers and reduce the magnitude of under-recovered costs should large load customers leave the system after signing a contract or project energization. Regulators in several states[18] are revising large load tariff and contract provisions to address at least 11 elements, including:

16 Comparable annual electricity growth rates in the 1950s and 1960s were driven by population growth and consumer demand for new appliances and air conditioning more than large loads.

17 In some cases, these changes also address on-site generation provisions. These can be relevant to large loads, particularly where the generation is behind the customer meter and alters the customer's electricity service needs.

18 These revisions are tracked in the Smart Electric Power Alliance (SEPA) and N.C. Clean Energy Technology Center's "DELTa: Database of Emerging Large Load Tariffs," https://sepapower.org/large-load-tariffs-database/.

a. **Demand (MW) and load factor threshold:** Minimum thresholds above which a customer is eligible for or must take service under the tariff

b. **Contract term:** Minimum number of years that the customer must take service under the tariff

c. **Load ramp:** The number of years before full contract capacity can be billed, and the billing demand during those years

d. **Contract modification:** The terms under which the customer can exit or modify the electric service agreement (ESA), including notice period and exit fees

e. **Demand charge**: Monthly charge per kW of billing demand

f. **Billing demand:** Calculation of monthly billing demand, including minimum demand based on contract capacity, prior months' demand, and fixed absolute minimum

g. **Energy and reactive power charge**: Per-kWh energy charge and per-kVAr charge for reactive power consumption above a threshold

h. **Collateral requirements:** The amount of collateral that must be posted and credit qualifications for an exemption

i. **Interruptions and demand response:** Interruptions in service and requirement or prohibition of demand response

j. **On-site generation:** Rules around on-site generation that operates while connected to the grid and how that generation might participate in demand response (excludes back-up generation, which requires site to be disconnected)

k. **Utility cost recovery:** How a utility recovers its costs, manages risk, and treats large load customers in regulatory processes[19]

Some of these elements may reduce project uncertainty by increasing a customer's short- and long-term financial commitment to the project, and thus could reduce financial risk to the utility's other customers. Items (a), (b), (c), and (j) above provide useful information for load forecast practices used today, while items (d) and (i) are rarely considered in today's load forecasts.

19 Adapted from Wood Mackenzie (2025).

As discussed in the section "Large Load Forecasting Practices Today," the customer interconnection process includes various customer agreements and contracts—these vary considerably from utility to utility. Modifications to tariffs and contracts can improve accounting for uncertainty, by requiring information needed for load forecasts at earlier steps in the process, increasing clarity of the five large load forecast metrics, and obtaining information about the customers' uncertainty about the submitted data. The importance of requiring this information early in the process, even with some expression of uncertainty, is particularly important for those utilities that prefer to defer formal contracting (ESAs) until roughly a year prior to energization, when both the customer and the utility have a clear understanding of what service is to be provided and at what cost. As these modifications improve information flow to the large load forecast, they should improve application of weighting factors and other practices discussed in the prior section.

But perhaps even more important, these higher financial requirements often enhance a large load customer's commitment to its proposed facility and may increase the project realization and load realization metrics in a load forecast.

Higher financial requirements often enhance a large load customer's commitment to its proposed facility and may increase the project realization and load realization metrics in a load forecast.

Because an inaccurate load forecast can drive a utility to invest billions of dollars in potentially unneeded transmission and energy production, authorities could explore whether a large load can be held accountable for an inaccurate load forecast. Requiring customers to provide clear expressions of interest up front, including information on whether the customer is exploring alternative interconnection options in other locations, should improve utilities' and regions' understanding of potential future large load volumes and timing. It will take a decade or more to be certain that today's practices have led to both financial and grid reliability for tomorrow's customers. Thus, while conceptually straightforward, these policies cannot yet be shown to have demonstrated success.

Affiliate and Gigawatt Uncertainty

Two related, emerging challenges are the large concentration of large loads across affiliated sites within a system or market region and the emergence of gigawatt-scale facilities. According to Grid Strategies, about half of data center load planned for service through 2029 is at least a gigawatt in size (Wilson et al., 2025). In each of these cases, a single customer's decision to cancel interconnection requests can seriously disrupt both the interconnection process and the transmission and resource planning processes.

The financial implications of such disruptions can be addressed through tariff, contractual, and regulatory measures, as discussed above. Interconnection study costs are commonly paid up-front by large load customers, and utilities can review their current requirements to ensure that they adequately deal with the additional costs of revisiting work that includes load associated with cancellations. Similarly, construction costs can be managed through financial security measures such as advance payment or refundable deposits.

Large load project cancellations may cause schedule delays for generation and other load projects because they could require the utility to re-study transmission and resource options to meet the rest of outstanding interconnection requests. It is not clear how to manage or reduce these risks.

An important emerging practice is to require prospective loads to disclose alternative sites under consideration, with several examples (e.g., Texas Senate Bill 6) discussed in the section "Large Load Forecasting Practices Today." However, to use such disclosures to reduce uncertainty in large load forecasts, two steps are needed. First, the disclosure needs to go beyond simply providing a list of other sites under active development, providing enough information about the customer's business plans sufficient to understand which projects might be alternatives or substitutes that could be cancelled later. Second, utilities and other planning authorities need to develop internal practices for applying such disclosures to the customer's interconnection requests and across the utility's interconnection, transmission, and resource planning activities.

Another emerging practice is for large load customers to construct on-site generation to serve their own electricity needs with minimal grid reliance. To date, this practice is concentrated among prospective gigawatt-scale data center customers, whose "speed to power" business model is challenged by the slow pace of transmission and generation resource development (Wilson et al., 2025). The PJM independent market monitor has proposed that "the best way to address the uncertainty in the load forecast that results from new large data center loads is to require the loads to bring their own new generation" (Monitoring Analytics, 2025).

Recommendation 5: Reduce Uncertainty in Regional Large Load Forecast Practices

Many regional load forecasting authorities (such as RTOs) are developing guidelines or practices that utilities must use when submitting large load forecast data to the region. ERCOT, SPP, and PJM have each made progress toward establishing such guidelines. A new requirement for customer-specific information by ERCOT provides a model of how a region might gather the data necessary to internally align utility forecasts to create a consistent forecast.

Regional authorities typically do not have access to the same data as utilities that communicate directly with customers about interconnection requests. To overcome this challenge, ERCOT recently adopted a requirement for transmission service providers to fill out a "Request to Energize a New Standalone Large Load" form (ERCOT, 2025c; ERCOT, 2025d). This form gives ERCOT and the serving transmission utility substantial customer-specific information needed for planning and interconnection analysis, consistent with ERCOT's Network Operations Protocol (ERCOT, 2025e).

FERC may soon require other transmission providers to implement standard guidelines, as part of the large load interconnection rulemaking recently initiated at the direction of the U.S. Department of Energy (FERC, 2025c). Specifically, the department argued that "it has become necessary to standardize interconnection procedures for [large] loads, including those seeking to share a point of interconnection with new or existing generation facilities (hybrid facilities)" (FERC, 2025b).

As regions and other multi-jurisdictional utility systems pursue greater standardization of interconnection procedures, including information needed to inform load forecasts, there are some potential challenges. First, state regulators may direct utilities on which prospective loads to include in their forecasts (e.g., requiring a contract such as an ESA). This direction could lead to inconsistencies between utility forecasts and data submitted into regional load forecasts. While the project team did not identify specific examples, regional authorities may wish to monitor this. Second, unintentional disparities could result in the use of specific or similar terminology being applied to different elements and practices among jurisdictions. For example, a letter of authorization (LOA) in one jurisdiction may obligate a customer for all costs including facility construction, but in another jurisdiction a separate agreement might be required for facility construction costs. Several project team members were aware of significant differences in terminology between different utilities and transmission providers for similar, but not identical, steps in the interconnection process.

Addressing inconsistencies between utilities will be challenging for regional transmission planners and providers. Regions could obtain customer-specific data and obtain publicly sourced data. These data could be used to adjust the aggregated large load forecasts to compensate for duplicative large load interconnection requests or recent project delays. Such adjustments could create justifiable inconsistencies between the regional load forecast and the members' aggregated forecasts.

While it may not be necessary to achieve full alignment across all load forecasting authorities in the country in forecasting practices, convergence on consistency in terminology, classifications, and other key components of large load forecasting should improve understanding and application of the forecasts.

Recommendation 6: Improve Geographical Detail

When transmission and resource planning are well aligned, planners can more accurately identify how large loads will drive requirements for transmission investments and changes in resource adequacy requirements. While the locations of contracted large loads can be included in a load forecast with geographical specificity, the location of other large loads in the forecast (e.g., based on a weighted percentage of prospective loads) will necessarily be more general. According to information reviewed by the project team, large load forecasts geographically characterize new loads at either the individual customer site for projects under contract or at the system level for other large load forecast data.[20]

Disconnects between system level and more geographically specific zonal level forecast requirements can limit the ability to plan for local reliability and manage congestion effectively. Without more granular geographical detail, transmission planners and operators cannot anticipate localized constraints and ensure adequate infrastructure, especially for long-term transmission projects serving high-growth areas.

As discussed in the ESIG Large Loads Task Force report *Planning for Large Load Flexibility in Resource Adequacy,* while some utilities' resource adequacy models utilize a "copper-sheet" assumption (treating the system as a single, unconstrained electrical region), most utilities and system operators use zonal or transfer-limited models

20 A similar conclusion is reached in CRA (2025).

that reflect underlying transmission constraints and regional capacity deliverability. To support this approach, large load forecasts may need to specify zones or sub-regions where new loads are expected to materialize. This zonal resolution helps planners evaluate how large-load additions will affect local capacity requirements, where new resources may be needed, and how transmission limitations could influence capacity requirements. Although transmission planners may need precise nodal locations for interconnection studies, resource adequacy analyses can typically operate effectively at a broader zonal level. Thus locational detail about large load applications is needed so large load forecasts can meaningfully inform regional and system-wide reliability planning.

If a transmission plan requires zonal information that is not immediately available, one possible solution is for the planners to identify areas with and without near-term zonal constraints or inadequacy. The system-level large load forecast could then be allocated to zones on the assumption that new customers are more likely to select areas of the system with minimal constraints. In the near term, these considerations may be most important for regional transmission planning authorities.

Recommendation 7: Seek Continuous Improvement Through Forecast Validation

Most load forecasting authorities conduct validation studies to improve the accuracy of load forecast methods and, by extension, the reliability of decisions over long-term planning horizons. The project team understands that some utilities with significant data center history perform internal forecast validation. But the project team was not able to identify any published large load forecast validation studies, even for utilities that publish validation studies of the traditional component of the load forecast.

This is understandable because most utilities and regional planners did not make large load forecasts until 2023 or 2024. Often, load forecasts lack sufficient history to validate prior forecasts. However, by 2026 or 2027, many utilities will likely be in position to begin assessing, validating, and learning from their past large load forecasts. Early validation efforts could yield near-term improvements in forecasting large loads.

Better data collection and management practices are critical for large load forecast validation. At present, many utilities receive information on projected load characteristics through interconnection applications, service contracts, and/or customer engagement, but these data may not be organized in a way that allows for systematic comparison to realized outcomes. Without deliberate tracking of these data as received, unnecessary effort may be required to reconstruct the data needed to conduct forecast validation studies.

The data requirements for future validation studies by utilities and regional entities would include the following information consistent with the large load metrics discussed above:

- Project type, by industry sector and type
- Project realization outcomes, including intermediate milestones achieved before cancellation, for projects that do not achieve energization
- Energization dates, tracked against original customer projections and internal (utility) expectations
- Load realization, comparing actual peak demand with both customer-stated values and internal forecast assumptions, and tracking any future changes in customer contract demand and service requirements
- Load ramping, documenting how actual load buildout compares with expected schedules
- Load factors (and, ideally, shapes), documenting how actual load factors compare with expectations

If utilities and other load forecasting authorities are not yet tracking and storing such information, doing so would enable future improvement.

Assuming data availability, the primary challenge of forecast validation lies in bridging the gap between multi-year forecast horizons and the need for timely validation to

support decision-making. To quantify accuracy, statistical error metrics are useful—such as mean absolute percentage error (MAPE) or root mean square error (RMSE) for deterministic forecasts or Brier score and continuous ranked probability score (CRPS) for probabilistic forecasts; however, it is impractical to wait years to confirm whether a forecast was correct. This difficulty is compounded by the novelty of many large load types, which often lack sufficient historical data for robust modeling and back-testing. As a result, validation strategies must rely on alternative approaches, such as scenario analysis, proxy data, and continuous model refinement, to ensure forecasts remain credible and actionable.

Developing New Information Resources and Forecasting Practices

The prior section discussed how load forecast accuracy may be improved with additional data, and the practices recommended are, for the most part, demonstrated by one or more existing load forecasts (as reviewed in the section "Large Load Forecasting Practices Today"). In contrast, this section discusses information resources and practices that could improve large load forecasting but are not yet in practice today. In the project team's view, building these resources and practices requires funding, adoption of regulations, or changes to organizational data-sharing policies that can best be accomplished through coordination at the regional, national, or North American level. At least three potential practices need further research or institutional development:

- **Data for large load forecast metrics:** Linking customer type and business model to granular, historical, or engineering projections
- **A maturity assessment framework for large load projects:** Increasing consistency of weighting and modeling practices, especially for data centers
- **Load flexibility standards and metrics:** Determining methods to identify the quantity of flexible load that various types of large loads can provide

Load forecasting authorities and their regulators are best suited to develop the appropriate standards, data resources, and tools to address these forecasting gaps, ideally in collaboration with the data center industry and other stakeholders. For large load forecast metrics, there is a clear benefit to adopting standardized information collection from load applicants, ideally with some data made available through a shared data resource. To build such a shared data resource, utilities and regulators will need to agree to the information needs, collection methods, and data repository and adopt privacy practices that allow secure sharing of critical information related to large load applications and their actual energy use.

Recommendation 8: Collect Large Load Forecast Data in a Shared Database

As discussed in the section "Using Available Data to Improve Forecast Accuracy," current practices rely heavily on customer-provided data, historical utility experience, and *very* limited industry data-sharing initiatives. Few utilities have sufficient historical data to assess the five load forecast metrics (see Figure 16, p. 33) for each type of large load in their territory (e.g., data centers and manufacturing facilities).

Those utilities that have sufficient historical data for large loads are using those data to reduce forecast uncertainty. But other utilities must handle large-scale load interconnection requests without access to such historical data. There are two ways for them to obtain it: wait several years until they gain experience or obtain it from a national data source. As previously noted, most load forecast authorities are not sharing data or assumptions; independent large load forecasts are not yet available from a research organization, although commercial vendors publish estimated load and energization date for data centers and some other types of large load projects.[21]

One potential solution is for national research organizations to support the development of a framework for aggregating anonymized customer data, enabling the creation of a

21 Examples include ABB/Velocity Suite, Baxtel, Cleanview, S&P Global, and Yes Energy.

comprehensive data library for many types of large loads. Despite the promise of this approach, significant barriers exist, including stringent customer privacy requirements and legal complexities associated with data sharing. The project team's understanding is that EPRI has made the most progress to date in assembling large load data. It would be helpful for regulators, utilities, and large load customers to support continued work collecting data and building large load models, with the expectation that those resources will be available to utilities and other power industry planning authorities.

A large load database could inform the development and adoption of consistent classifications of large load types, as discussed in the section "Using Available Data to Improve Forecast Accuracy." Large load type classifications should reflect load forecast metrics for actual facilities with relatively similar load forecast metrics and common characteristics such as size, business model, and—where relevant—geographical, seasonal, or weather characteristics that are important for applying the data in other conditions. On-site generation may not affect large load classifications but will affect how those loads are treated in utility planning.

A database could solicit data for the five large load forecast metrics (see Figure 16, p. 33). Developing clear and consistent data specifications for these five metrics will likely require some iteration with participating utilities. Assembling the data will also require attention to customer privacy regulations and concerns, so that the data supplied and stored in the database do not reveal specific facility business practices. Ultimately, such a database could include average load forecast metrics for dozens of large load types, as well as measures of variability such as standard deviation.

Of the five metrics, load shape may be the most difficult to accurately determine and, hence, starting more simply with load factors would be easier though less informative for resource planning. Enhancing the load factor metric to a load shape metric requires more complex specifications and practices; load shapes need to be described in terms of weather conditions, climate sensitivity, and any use of multi-year averaging periods. Load shapes are also likely to be the most sensitive metric from a customer-privacy perspective, and sharing this information will be easier if data-sharing practices have already been developed for less complex and sensitive measures.

The process of building and updating a large load database would help create common definitions that evaluators can use to compare performance across different models and methodologies. Collaboration on this database could also elevate best practices and improvements, reduce duplication of effort, and accelerate the development of robust validation techniques to improve forecast depth, accuracy, and credibility.

The process of building and updating the database would help create common definitions that evaluators can use to compare performance across different models and methodologies. Collaboration on this database could also elevate best practices and improvements, reduce duplication of effort, and accelerate the development of robust validation techniques to improve forecast depth, accuracy, and credibility.

Recommendation 9: Apply Consistent Load-Weighting and Modeling Practices

Load forecasts can also be improved by enhancing and standardizing load-weighting and modeling practices. As illustrated through the project team's existing practices, research, utility, and regional load forecasting authorities apply professional judgment to data from customer load requests to create load forecasts. As discussed in the section "Large Load Forecasting Practices Today," those professional judgment practices vary widely across large load forecasts, as with whether to discount pre-contract large load interconnection applications (Archetype 2) or only include contracted load (Archetype 1).

Not every utility's circumstances and load applicants are the same, so some variation in large load forecasting practices is to be expected. But the extent of this variation indicates that the industry has not standardized around a set of effective practices. In contrast, traditional long-term forecasting practices have converged on a set of consistent statistical and econometric practices across the industry.

NERC's preliminary draft reliability guideline for large loads includes a recommendation that Transmission Planners and Planning Coordinators (as defined by NERC) establish a large load maturity assessment framework that defines the different phases of a large load request's lifecycle using clear criteria. NERC's draft suggests that the following project milestones could be included in the maturity assessment (NERC, 2025b):

- Data-sharing agreements
- Interconnection agreements
- Financial security posted
- Proof of site control
- Construction status
- Development permit status
- Environmental permit
- Land status
- Procured equipment

As noted in "Large Load Forecasting Practices Today," some load forecasts already use similar milestones to apply weighting factors to large loads in their interconnection pipelines.

NERC's draft guideline explains that if large load interconnection requests are not reflected in long-term planning models, that can make the bulk power system less reliable because transmission planning assessments and studies won't reflect future loads and energy needs. Within utility and regional planning organizations, different departments handle generator interconnection, transmission upgrades, and resource adequacy planning using mismatched planning cycles, so they need to align the various departments' understanding of large load project attributes and timing (NERC, 2025b). Interdepartmental coordination is not a new load forecasting challenge, but the pace and scale of large load projects now places greater demands on that coordination to ensure alignment around updated information from the large load forecast.

As NERC suggests, using a common a maturity assessment framework would help all departments align around a common understanding of large load project status, improve the assumptions and data treatment used for large load project modeling and infrastructure planning, and mitigate some of the risks posed by inaccurate long-term forecasts (NERC, 2025b). In Box 6 a model maturity assessment framework for capital cost estimating is shown. While there are differences between assessing the maturity of an internal capital project and a prospective project from a customer, a large load project maturity assessment framework could follow a similar practice.

BOX 6

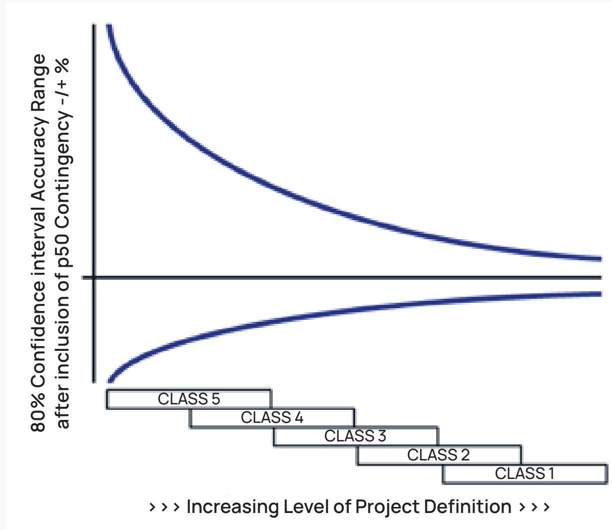
A Model for Large Load Maturity Assessment

The Association for the Advancement of Cost Engineering's Cost Estimate Classification System offers a potential model for a maturity assessment framework (AACE International, 2020) (Figure 20). This classification system identifies projects with the lowest level of project scope definition as "Class 5," and projects with the highest level of project scope definition are "Class 1." Project maturity can be thought of as the completeness of a project's definition. However, a project definition includes many deliverables that vary based on a project's characteristics, so assessing completeness is not straightforward. The project maturity determines the estimate class, which yields an expected accuracy range for its cost estimate.

A project maturity matrix is used to assign scores for whether various types of general project data are preliminary or defined and whether key deliverables are started, preliminary, or complete. AACE International has published recommended practices that identify the correspondence between those classifications and the expected components of many types of projects, including power transmission lines and associated infrastructure projects (AACE International, 2020).

FIGURE 20

AACE International's Accuracy Ranges for Cost Estimates, by Maturity Matrix Classification



AACE International's Cost Estimate Classification System links project maturity to expected accuracy ranges. Early-stage projects (Class 5) have wide accuracy bands, while fully defined projects (Class 1) have narrower ranges. This framework provides a model for applying maturity-based accuracy ranges to the five large load forecasting metrics.

Source: AACE International (2020).

For example, a large load project at a Class 5 level of maturity might be a simple customer inquiry with information about location and general load requirements, while a Class 1 level of maturity might require a fully engineered site plan, full contracting, and a signed ESA.

A large load maturity matrix and assessment could indicate expected accuracy ranges for the project's five load forecast metrics (project realization, load realization, energization date, load ramping, and load factor or load shape). To deliver an equivalent rigor of practice as the AACE recommended practices, such a framework would need to be informed by data from utility experience with large load interconnection requests, as might be constructed in the forecast metric database described in Recommendation 8.

Recommendation 10: Adopt Forecast Standards for Load Flexibility

As is discussed in further detail in the ESIG Large Loads Task Force report *Planning for Large Load Flexibility in Resource Adequacy*,[22] there is substantial opportunity

22 See https://www.esig.energy/large-loads-task-force.

for regulators and utilities to use load flexibility to meet reliability, affordability, and economic development objectives serving new customer load requests (Norris et al., 2025). For these reasons, load flexibility is increasingly being considered as a requirement for new large loads to connect to the grid.[23]

- Texas's Senate Bill 6 directs ERCOT to develop a reliability service to competitively procure demand reductions from large load customers with a demand of at least 75 MW, to be deployed in the event of an anticipated emergency condition. This program is not expected to provide flexibility that reduces the need for generation resources and transmission upgrades (Aslam et al., 2025).
- PJM is targeting a December 2025 filing of reliability-focused solutions to ensure that large load additions can continue to be integrated rapidly and reliably, without causing resource shortages and while recognizing jurisdictional boundaries and data center relationships with existing utilities.[24]
- SPP has proposed the Conditional High Impact Large Load Service (CHILLS) framework. CHILLS would offer an expedited 90-day interconnection study leading to five years of interruptible (i.e., deferred upgrade) transmission service in exchange for agreed curtailment rights.
- In an Oregon Public Utility Commission proceeding covering a range of large load issues, an administrative law judge found that the opportunity for load flexibility is "entwined" with topics such as the need for a data center rate class, a load-following rate, and cost allocation studies (Oregon PUC, 2025).

The project team has not included load flexibility as one of the five large load forecast metrics. While the concept is sound, there are substantial challenges to defining a load flexibility metric that would be included in a load forecast for the purpose of planning transmission and generation resources.

Defining Load Flexibility

Load flexibility spans a range of technologies and practices. In the context of large loads, it can refer to both load reduction and the use of on-site storage or generation resources to reduce the net load required by a large load customer. It is not yet clear how large loads will develop and use load flexibility capabilities.

The EPRI DCFlex project has drafted a standard with five tiers of load flexibility services:[25]

- Supports grid during disturbances
- Self-serves during transmission outages
- Supports grid during peak stress
- Provides fast or long flexible response
- Acts like dispatchable capacity

Some of the metrics that emerge from the development of such a standard could be used in a large load forecast.[26] Dispatchable capacity would be measured in familiar terms of size (megawatts), speed, and duration. Quantify-

23 Note: This report focuses on mid- and long-term load forecasts. Short-term forecasting for operational purposes is covered in the ESIG Large Loads Task Force report *Wholesale Market Design and Operations for Systems with Large Loads: Current Practices and Recommendations*.

24 For PJM, "utilities" refers to Load Serving Entities and/or Electric Distribution Companies. See https://www.pjm.com/committees-and-groups/cifp-lla.

25 The StarFLEX™ standard. EPRI, presentation by Anuja Ratnayake to the ESIG Large Loads Workshop (October 30, 2025).

26 Other metrics would not be applicable. For example, the level of voltage support from a data center to the grid during disturbances is not considered in a long-term load forecast.

ing the capability of a large load project to support the grid during peak stress will require clarity on the severity of the grid stress event and the duration of support needed, much like the demand response metrics being considered in either a load forecast or a resource plan.

During a discussion on load flexibility at the October 2025 ESIG Large Loads Workshop, panelists generally agreed that load flexibility programs must be designed to match large load participants' motivation. For data centers, this is generally understood to mean that "speed to power" (faster interconnection to the grid) is offered in exchange for a binding commitment to provide some form of load flexibility that supports grid reliability.

Load flexibility programs need to align with large load participants' motivation. For data centers, this is generally understood to mean that "speed to power" (faster interconnection to the grid) is offered in exchange for a commitment to provide some form of load flexibility that supports grid reliability.

Voluntary Efforts to Enable Load Flexibility for Data Centers

Utilities and regional grid operators generally have little experience with load flexibility from large data centers. A notable exception is the demonstrated electricity price response from some large loads in ERCOT, but those are highly price-sensitive loads like crypto miners rather than large data centers. Yet even ERCOT has found that "forecasting flexible behavior is difficult" (Springer, 2024). Addressing this gap are a variety of collaborative and individual efforts to develop policies, practices, and technologies to advance data center load flexibility.

EPRI's program to develop practices and policies to advance data center load flexibility, as shown in Figure 21, has high visibility and involves the collaboration of data center companies and utilities.

FIGURE 21
EPRI DCFlex Program Overview

EPRI's Data Center Flexibility (DCFlex) program aims to develop standardized methods for evaluating and implementing load flexibility at large data centers. The figure summarizes the program's collaborative framework among utilities, data center operators, and research partners, highlighting efforts to define metrics, pilot demonstrations, and quantify flexibility potential for grid support.

Source: A. Ratnayake's presentation to the ESIG Large Loads Workshop, October 30, 2025.

A wide variety of efforts are under way to secure data center participation in long-term, guaranteed load flexibility programs using on-site storage, generation, and load management. Some examples include:

- **Traditional demand response:** At least one data center is participating in California's Base Interruptible Power (BIP) program (Enchanted Rock, 2023). The BIP program is an emergency demand response program with events triggered by CAISO or local system emergencies.
- **Software for load curtailment:** Work is progressing on software-based data center demand flexibility programs. For example, Emerald AI's Phoenix, Arizona, pilot project recently studied load curtailment of up to 50%, and additional demonstrations are reportedly in progress (Colangelo et al., 2025; Vaidhynathan et al., 2025).
- **On-site battery storage:** In principle, storage could be used to meet short- or long-term load flexibility needs. Current projects are designed to respond to relatively short (e.g., two-hour) power back-up needs, not longer curtailments. Verrus is building data centers with four hours of 70 MW battery storage demand response capability for load curtailment in excess of 50% without impacting data center operations, with operation forecast for late 2026 (Vaidhynathan et al., 2025; Giacobone, 2025). Tesla has installed battery storage and other behind- and in-front-of-the-meter resources to "shape" load and provide grid capacity at its data centers (Tesla, 2025).
- **On-site generation:** Data centers are increasingly turning to on-site generation, but only some types of on-site generation can contribute to load flexibility. Back-up generation is necessary to meet the customer's high operational reliability needs, but the use of natural gas or diesel generators is often constrained by air-permitting requirements, so these are unlikely to be used for load flexibility. Larger gas-fired generation units, installed behind- or in-front-of-the-meter, are being deployed at several data centers, and these could either provide grid-dispatchable power or effectively remove a portion of a data center's load from the grid at most times.[27]

If flexibility information is not considered in planning until after the project is fully ramped up to its expected level of demand, it will be too late to modify the project's utility infrastructure requirements.

Generally speaking, the intent of these efforts is to more rapidly integrate new loads and reduce capital costs while meeting reliability and other grid needs.

The Challenge of Developing a Load Flexibility Metric for Large Load Forecasts

Large load forecasts reviewed by the project team do not explicitly account for demand flexibility as a way to permanently reduce large load peak demand and infrastructure needs. The project team appreciates that information on flexibility may not be reliable at early stages of project development. But if flexibility information is not considered in planning until after the project is fully ramped up to its expected level of demand, it will be too late to modify the project's utility infrastructure requirements.

It is not strictly necessary for load flexibility to be included in a load forecast. Information about load flexibility may be shared directly with transmission planning and generation planning staff. However, this approach risks significant inconsistency in how load flexibility is considered, and customer privacy considerations may make this impractical for regional planning purposes.

Whether used in a load forecast or in resource planning, the development of a load flexibility metric (or likely, a set of metrics) is likely to build upon prevailing practices for demand response programs (Carvallo and Schwartz, 2023). Demand response metrics usually include (a) measures of verified demand response program effectiveness, and (b) forecast program enrollment.

27 The project team understands that most data center owners would prefer not to have organizational responsibility for, and direct financial ties to, their own grid-scale generation units. Also, most on-site generation includes plans to fully connect the data center to the grid for both operational reliability and to provide power when the on-site generation is under maintenance.

Defining load flexibility metrics using concepts related to *price-based* demand response is probably not helpful for load forecasts. According to LBNL, best practice treatment of price-based demand response follows five principles, one of which is that price-based demand response "be treated as a resource by creating supply curves with a diverse set of rate options, and not as load reduction in the load forecast used in the capacity expansion model" (Carvallo and Schwartz, 2023).[28] The impact of price-responsive demand in large load forecasts may be limited because the value of data center operations (with fast performance requirements and short equipment depreciation rates) substantially exceeds the economic value of potential demand response revenues.[29]

For most other types of large loads (e.g., industrial, manufacturing, and mining), information reviewed by the project team suggests that standard practices for considering load flexibility in forecasts and planning models will be sufficient. Depending on the load flexibility programs offered by the utility and the new large loads' eligibility, applying load flexibility to these non-data-center customers should be straightforward if program enrollment can be forecast projected with reasonable certainty.

For data center customers, however, the challenges of projecting program enrollment and measuring program effectiveness will be heightened, for three reasons:[30]

- As discussed above, there is very little experience, much less verification, of load flexibility response for large data centers, with the exception of the demonstrated electricity price response from highly price-sensitive industrial and crypto mining loads in ERCOT.
- Data center load forecasts remain highly uncertain, compounding the uncertainty regarding potential data center demand flexibility resources.
- For multi-tenant data centers, contract terms between the data center operator and its tenants may constrain options for providing load flexibility. For example, some tenants may not have options to shift computing workload to another data center, particularly for the highest-sensitivity computing services.

28 Among the few examples of load flexibility being widely included in load forecasts are price-responsive rates for large customers and rates for managed electric vehicle charging.

29 The energy cost associated with a data center can be less than 10% of its total capital plus energy costs (Cottier et al., 2025). Even during peak pricing hours, energy costs are very low compared to the potential for foregone data center revenue. Businesses expect to recover depreciation (and profit on) their investments. Data center servers can depreciate in three to seven years, which creates pressure to generate revenue in virtually every possible hour, given their high investment cost—particularly that for AI computers (ITSco, 2025; Stream Data Centers, 2025). Note that the data center facility (building and major infrastructure) is often estimated to have a lifetime of 30 years.

30 Very similar factors challenge the application of load flexibility to hydrogen production facilities. The project team did not explore this technology in depth.

Conclusion

This ESIG Large Loads Task Force investigation into load forecasting concludes that there is both need and an opportunity to reduce uncertainty and improve accuracy in forecasting future large load peak electricity demand and energy needs. Forecasting inaccuracies can yield inefficient transmission and resource planning or leave utilities unprepared to serve new customers. The massive scale of anticipated large load growth—for individual facilities and collectively within and across regions—increases the reliability and financial consequences of load forecast errors.

Current large load forecasting methods lack transparency and can vary significantly between utilities, regions, and forecast purposes. Different types of large loads have different development patterns and paces. Gaps in data availability and large load history make forecasting even more difficult. Therefore, many load forecasts use weighting methods and thresholds to evaluate and discount prospective large loads.

Data center electricity demand is particularly difficult to forecast because the facilities are large and have numerous characteristics that increase uncertainty. These characteristics include that:

- Developers are proposing many large data centers, and both individual and aggregate projects will have significant impacts upon the grid.
- Many proposed data centers could be delayed or cancelled if other data centers under development by the same company move forward.
- Data center electricity load shapes are new and evolving, and currently not well defined, so their load can be difficult to predict and serve with reliable grid infrastructure and operations.
- Many data center applications contain limited engineering detail despite the fact that they seek very fast interconnection to the grid.

Current load forecasts do not have much geographical detail or treatment of load flexibility, which is increasingly considered as a means to expedite grid interconnection of large loads. Since the primary objective of load forecasts is to inform transmission and resource planning, these gaps reduce the value that forecasts can provide to these downstream processes.

Some utility rate tariff reforms are helping to reduce load forecast uncertainty by imposing significant financial requirements from the beginning of the project development process. But because so many large loads have huge financial resources, such reforms by themselves are unlikely to remove all major uncertainties.

Based on these findings, the task force offers 10 recommendations to improve large load forecasting.

Recommendation 1: Use all five large load metrics to create a large load forecast. A well-structured large load forecast will clearly describe and use the five large load metrics (project realization, energization date, load realization, load ramping, and load factor or load shape) (Figure 16, p. 33).

Recommendation 2: Develop a consistent framework to differentiate among types of large loads. A large load classification system can help to consistently identify large load types across a forecast. A database of large load forecast metrics, as discussed in Recommendation 8, could inform such a load classification system.

Recommendation 3: Account for uncertainty. Optimal planning of utility transmission and generation investments means accounting for uncertainty in both front-end and back-end risk. Front-end risk refers to uncertainty in the quantity and timing of infrastructure needed to serve new large loads. Back-end risks center on whether the infrastructure and investments built to serve new loads will remain needed and used. However, many large load forecasts do not currently address back-end risks and overlook attrition or systemic risk of customers reducing or cancelling service. This omission could lead to inefficient or excessive utility or regional infrastructure investments.

Recommendation 4: Increase certainty through large load financial requirements. The main method used to reduce near-term uncertainty is to modify tariff and contract requirements for large loads, such as by requiring various forms of financial commitments and security from the applicant. Disclosure requirements and the increasing practice of customer-sited generation are emerging practices to reduce uncertainty regarding the host system's financial risks.

Recommendation 5: Reduce uncertainty in regional large load forecast practices. Consistent with Recommendations 2 and 8, continuing standardization by regional transmission authorities and FERC for submission and evaluation of customer-supplied information will help improve accuracy of large load forecasts.

Recommendation 6: Improve geographical detail. Large load forecasts may need to incorporate information on large load projects' geographical locations by geographical zones or subregions and determine how to geographically allocate future large loads for planning purposes. This is particularly important for regional transmission planning authorities.

Recommendation 7: Seek continuous improvement through forecast validation. As large load forecasting evolves and more information becomes available about the actual performance of large loads connected to the grid, it will be helpful to use this information to validate and improve future large load forecasting models and methods.

Recommendation 8: Collect large load forecast data in a shared database. Nearly every large utility needs access to historical data for each type of large load, but most utilities lack large load experience and historical data. Establishing such a database will require a developing a framework for obtaining, managing, and protecting anonymized customer data; categorizing those data by large load type (Recommendation 2); and creating specifications for each large load metric.

Recommendation 9: Apply consistent load-weighting and modeling practices. Creating and applying a project maturity framework would define the phases of a project's development path and use them for consistent load-weighting and modeling practices in large load forecasts.

Recommendation 10: Adopt forecast standards for load flexibility. As large load flexibility options evolve, large load forecasts could include load flexibility among the metrics and treat it consistently across all planning activities.

References

AACE International (Association for the Advancement of Cost Engineering International). 2020. "Cost Estimate Classification System—As Applied in Engineering, Procurement, and Construction for the Power Transmission Line Infrastructure Industries Recommended Practice No. 96R-18." https://www.pathlms.com/aace/courses/2928/documents/12530#. Figure 20 is used with permission of AACE International, 726 East Park Ave., #180, Fairmont, WV 26554. info@aacei.org; 304.296.8444; www.aacei.org.

AACE International (Association for the Advancement of Cost Engineering International). 2012. "Risk Analysis and Contingency Determination Using Expected Value, Recommended Practice No. 44R-08." https://www.pathlms.com/aace/courses/2928#.

AACE International (Association for the Advancement of Cost Engineering International). 2008. "Contingency Estimating—General Principles, Recommended Practice No. 40R-08." https://www.pathlms.com/aace/courses/2928#.

AEP (American Electric Power). 2025. Correspondence: "Status of Process for Signing Up New Schedule DCT Customers." September 11, 2025. p. 1, https://dis.puc.state.oh.us/CaseRecord.aspx?CaseNo=24-0508-EL-ATA.

APS (Arizona Public Service). 2023. "2023 Integrated Resource Plan." https://www.aps.com/en/About/Our-Company/Doing-Business-with-Us/Resource-Planning.

APS (Arizona Public Service). 2024. "Rate Schedule XHLF." https://www.aps.com/-/media/APS/APSCOM-PDFs/Utility/Regulatory-and-Legal/Regulatory-Plan-Details-Tariffs/Business/Business-NonResidential-Plans/ExtraHighLoadFactor.pdf.

Aslam, W., and R. Hytowitz. 2025. *Texas SB6 Explained: Addressing Large Load Impacts.* EPRI. https://www.epri.com/research/products/000000003002033410.

BloombergNEF. 2025. *AI and the Power Grid: Where the Rubber Meets the Road.* https://about.bnef.com/insights/clean-energy/ai-and-the-power-grid-where-the-rubber-meets-the-road/.

Carvallo, J. P., and L. Schwartz. 2023. *The Use of Price-Based Demand Response as a Resource in Electricity System Planning.* Lawrence Berkeley National Laboratory. https://eta-publications.lbl.gov/sites/default/files/price-based_dr_as_a_resource_in_electricity_system_planning_-_final_11082023.pdf.

CEC (California Energy Commission). 2024. "Data Center Load Forecasts, 2024–2040." Presentation to CEC Demand Analysis Working Group, October 21, 2024. https://www.energy.ca.gov/filebrowser/download/6686?fid=6686.

Cleanview. 2025. "Data Center Tracker." Accessed October 17, 2025. https://cleanview.co/.

Colangelo, P., A. K. Coskun, J. Megrue, C. Roberts, S. Sengupta, V. Sivaram, and E. Tiao. 2025. *Turning AI Data Centers into Grid-Interactive Assets: Results from a Field Demonstration in Phoenix, Arizona.* https://arxiv.org/abs/2507.00909.

Cottier, B., R. Rahman, L. Fattorini, N. Maslej, T. Besiroglu, and D. Owen. 2025. *The Rising Costs of Training Frontier AI Models.* Preprint, arXiv. https://arxiv.org/abs/2405.21015.

CRA (Charles River Associates). 2025. "Utility Planning Best Practices: Data Center Load Considerations." Docket No. EO-2026-0088, Item 5, Appendix A. Missouri Public Service Commission. https://efis.psc.mo.gov/Document/Display/855602.

Dominion Energy. 2025a. "2025 20-Year Data Center Forecast." Presentation to PJM Load Analysis Subcommittee, September 16, 2025. https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2025/20250916/20250916-item-04ai--dominion-data-center-large-load-request.pdf

Dominion Energy. 2025b. "2025 Biennial Rate Case Application." Virginia SCC Case No. PUR-2025-00058. https://www.scc.virginia.gov/docketsearch#caseDocs/146025.

Dominion Energy. 2025c. "Response to Piedmont Environmental Council Fifth Set of Interrogatories." Virginia SCC Case No. PUR-2025-00058. https://www.scc.virginia.gov/docketsearch#caseDocs/146025.

Duke Energy. 2025a. Docket No. E-100, Sub 207. Document Number: F-E-20251001-014. North Carolina Utilities Commission. https://starw1.ncuc.gov/NCUC/page/docket-docs/PSC/DocketDetails.aspx?DocketId=d4fa8ad5-1a2b-410e-8114-572ab8f7ec51.

Duke Energy. 2025b. *Carolinas Resource Plan.* "Appendix D: Load Forecast." https://www.duke-energy.com/our-company/about-us/irp-carolinas.

Elias, M., M. D. Ramsay, D. Deckelbaum, M. Bianchi, J. Osborne, and J. Miller. 2024. *Data Centers Part II: Power Constraints—The Path Forward.* TD Cowen. https://www.tdsecurities.com/ca/en/data-centers-2-power-constraints.

Enchanted Rock. 2023. "Enchanted Rock and U.S. Energy Partner to Provide Back-Up Power for Microsoft Data Center for Grid Outages." December 12, 2023. https://enchantedrock.com/enchanted-rock-and-u-s-energy-partner-to-provide-back-up-power-for-microsoft-data-center-for-grid-outages/.

ERCOT (Electric Reliability Council of Texas). 2025a. "ERCOT's Revisions to Adjusted Load Forecasts and Amended Draft Proposed Order." Docket No. 55999, Item No. 140. Public Utility Commission of Texas. https://interchange.puc.texas.gov/Documents/55999_140_1504530.PDF.

ERCOT (Electric Reliability Council of Texas). 2025b. "Long-Term Load Forecast Update (2025-2031) and Methodology Changes." Presentation to ERCOT Board of Directors Meeting, April 7, 2025. https://www.ercot.com/files/docs/2025/04/07/8.1-Long-Term-Load-Forecast-Update-2025-2031-and-Methodology-Changes.pdf.

ERCOT (Electric Reliability Council of Texas). 2025c. "Market Notice M-B062325-01, June 23, 2025." https://www.ercot.com/services/comm/mkt_notices/M-B062325-01.

ERCOT (Electric Reliability Council of Texas). 2025d. "Market Notice M-B100825-01, October 8, 2025." https://www.ercot.com/services/comm/mkt_notices/M-B100825-01.

ERCOT (Electric Reliability Council of Texas). 2025e. "Planning Guide, June 1, 2025, Sections 6.6, 9.6." https://www.ercot.com/files/docs/2025/05/20/June-1-2025-Planning-Guide.pdf.

ESIG (Energy Systems Integration Group). 2025. *Long-Term Load and DER Forecasting.* https://www.esig.energy/long-term-load-and-der-forecasting/.

Exelon. 2025. "Exelon Large Load Adjustment Proposal." Presentation to PJM Load Analysis Subcommittee, September 16, 2025, p. 4. https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2025/20250916/20250916-item-04d--exelon-large-load-request.pdf.

FERC (Federal Energy Regulatory Commission). 2025a. "Chairman Rosner's Letter to RTOs/ISOs on Large Load Forecasting." https://ferc.gov/news-events/news/chairman-rosners-letter-rtosisos-large-load-forecasting.

FERC (Federal Energy Regulatory Commission). 2025b. "Ensuring the Timely and Orderly Interconnection of Large Loads: Advance Notice of Proposed Rulemaking." Available as "Advanced Rulemaking Large Loads.pdf" at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20251027-4001.

FERC (Federal Energy Regulatory Commission). 2025c. "Interconnection of Large Loads to the Interstate Transmission System." Docket No. RM26-4-000. https://elibrary.ferc.gov/eLibrary/docketsheet?docket_number=rm26-4-000.

Georgia Power. 2025. "Budget 2025 Load and Energy Forecast 2025 to 2044." https://psc.ga.gov/search/facts-docket/?docketId=56002.

Giacobone, B. 2025. "Verrus Successfully Demos Its Flexible Data Center Technology." May 15, 2025. Latitude Media. https://www.latitudemedia.com/news/verrus-successfully-demos-its-flexible-data-center-technology/.

Gramlich, R., J. D. Wilson, R. Seide, Y. Raskovic, J. M. Hagerty, J. DeLosa III, and J. Pfeifenberger. 2024. *Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid*. Grid Strategies and The Brattle Group. https://gridstrategiesllc.com/unlocking-americas-energy-how-to-efficiently-connect-new-generation-to-the-grid/.

Hotaling, C., D. Mellinger, and A. Sommer. 2025. *Report on NIPSCO's 2024 Integrated Resource Plan*. Prepared by Energy Futures Group and submitted to the Indiana Utility Regulatory Commission, April 17, 2025. Indiana Utility Regulatory Commission. https://www.in.gov/iurc/files/NIPSCO-IRP-CAC-EJ-SUN-VS-Redacted-Comments-4-17-2025FINAL.pdf.

IESO (Independent Electricity System Operator). 2025. "IESO Demand and Conservation Planning Technical Paper: Large Step Loads." Toronto, Canada. https://www.ieso.ca/Sector-Participants/Planning-and-Forecasting/Demand-Research.

ISONE (Independent System Operator New England). 2025. "ISONE Response to Chairman David Rosner's 09/19/2025 Letter re Large Load Forecasting for America's Significant Electricity Demand Growth." https://www.ferc.gov/media/isone-response-chairman-david-rosners-09192025-letter-re-large-load-forecasting-americas.

ITSco. 2025. "GPU and Refresh Cycle Case Study." White paper. https://www.itsco.com/white-papers-gpu-and-refresh-cycle-case-study/.

Kou, H. 2025. *Power for AI: Easier Said Than Built*. BloombergNEF. https://about.bnef.com/insights/commodities/power-for-ai-easier-said-than-built/.

Masanet, E., N. Lei, and J. Koomey. 2024. "To Better Understand AI's Growing Energy Use, Analysts Need a Data Revolution." *Joule* 8(9): 2427–2436. https://www.cell.com/joule/fulltext/S2542-4351(24)00347-7.

MISO (Midcontinent Independent System Operator). 2025. "MISO Response to Chairman David Rosner's 09/19/2025 Letter re Large Load Forecasting for America's Significant Electricity Demand Growth." Docket No. EL25-109-000. Federal Energy Regulatory Commission. https://www.ferc.gov/media/miso-response-chairman-david-rosners-09192025-letter-re-large-load-forecasting-americas.

MISO (Midcontinent Independent System Operator). 2024. TO BE COMPLETED.

Monitoring Analytics. 2025. "IMM CIFP Large Load Additions Proposal." October 14, 2025. https://www.pjm.com/committees-and-groups/cifp-lla.

Morris, S. "Data Center Inside ERCOT Observations and Patterns." Presentation to ERCOT Large Load Working Group, August 14, 2025, p. 3. https://www.ercot.com/files/docs/2025/08/11/LLWG_DataCenterObs.pptx.

NERC (North American Electric Reliability Corporation). 2025a. "Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations." September 9, 2025. https://www.nerc.com/globalassets/programs/bpsa/alerts/2025/nerc-alert-level-2–large-loads.pdf

NERC (North American Electric Reliability Corporation). 2025b. "DRAFT Reliability Guideline: Risk Mitigation for Emerging Large Loads." https://www.nerc.com/our-work/guidelines/reliability-guidelines.

Norris, T. H., T. Profeta, D. Patino-Echeverri, and A. Cowie-Haskell. 2025. *Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in U.S. Power Systems*. Nicholas Institute for Energy, Environment and Sustainability, Duke University. https://nicholasinstitute.duke.edu/publications/rethinking-load-growth.

NYISO (New York Independent System Operator). 2025. *2025 Power Trends: The New York ISO Annual Grid and Markets Report*. https://www.nyiso.com/documents/20142/2223020/2025-Power-Trends.pdf.

Oncor. 2025. "Response to ERCOT's Request for Good Cause Exception for 2025 Regional Transmission Plan." Public Utility Commission of Texas Project No. 55999, Exhibit A, p. 5-6. https://interchange.puc.texas.gov/Search/Filings?ControlNumber=55999.

Oregon PUC (Oregon Public Utilities Commission). 2025. "Issues List Adopted." May 20, 2025. Docket No. UM 2377, pp. 2-3. https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=24470.

PacifiCorp. 2025. "2025 Integrated Resource Plan and Clean Energy Plan." Docket No. LC 85. Public Utility Commission of Oregon. https://edocs.puc.state.or.us/efdocs/HAC/lc85hac339442027.pdf.

PJM. 2025a. "Large Load Additions: CIFP Update." https://www.pjm.com/committees-and-groups/cifp-lla.

PJM. 2025b. "Total Demand Request for Large Load Adjustment." https://www.pjm.com/committees-and-groups/subcommittees/las.

PUCO (Public Utilities Commission of Ohio). 2025. "Opinion and Order (July 9, 2025)." P. 12, filed in Case No. 24-508-EL-ATA. https://dis.puc.state.oh.us/CaseRecord.aspx?CaseNo=24-0508-EL-ATA.

PUCT (Public Utility Commission of Texas). 2025. "Staff Discussion Draft, Draft NEW 16 TAC §25.194, Rulemaking to Implement Large Load Interconnection Standards Under PURA §37.0-561." Case No. 58481-31. https://interchange.puc.texas.gov/search/documents/?controlNumber=58481&itemNumber=31.

Riu, I., D. Smiley, S. Bessasparis, and K. Patel. 2024. "Load Growth Is Here to Stay, but Are Data Centers? Strategically Managing the Challenges and Opportunities of Load Growth." White paper. Energy and Environmental Economics (E3). https://www.ethree.com/data-center-load-growth/.

Shehabi, A., A. Newkirk, S. J. Smith, A. Hubbard, N. Lei, M. A. B. Siddik, B. Holecek, J. Koomey, E. Masanet, and D. Sartor. 2024. *2024 United States Data Center Energy Usage Report*. Lawrence Berkeley National Laboratory. https://doi.org/10.71468/P1WC7Q.

SPP (Southwest Power Pool). 2025a. "Load Forecast Risk Mitigation." Presentation by Brad Cochran on behalf of SPP Load Forecasting Task Force at SPP Strategic Planning Committee meeting, July 17, 2025. https://www.spp.org/documents/74396/spc%20meeting%20minutes_20250717_combined%20file.pdf.

SPP (Southwest Power Pool). 2025b. "Long-Term Load Forecasting Methods and Best Practices." https://www.spp.org/spp-documents-filings/?id=452073.

SPP (Southwest Power Pool). 2025c. "RR696 Integrate & Operate High Impact Large Loads.docx." Available in RR696.zip via "View Revision Request 696 (Integrate & Operate High Impact Large Loads)." https://www.spp.org/markets-operations/high-impact-large-load-hill-integration/.

Springer, A. 2024. "Large Loads in ERCOT—Observations and Risks to Reliability." Presentation to NERC Large Loads Task Force. North American Electric Reliability Corporation. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/lltf/lltf_kickoff_presentations.pdf.

STACK Infrastructure. 2025. "Comments of STACK Infrastructure, Inc Regarding Data Center Load Forecasting." California Energy Commission, Docket 25-IEPR-03. https://efiling.energy.ca.gov/GetDocument.aspx?tn=261716&DocumentContentId=98178.

Stream Data Centers. 2025. "With the Right Developer, Technological Progress Doesn't Mean Data Center Obsolescence." Brief. https://www.streamdatacenters.com/wp-content/uploads/2025/04/SDC-Brief-Data-Center-Obsolescence-20250416.pdf.

Tesla. 2025. "Battery Storage Applications at Data Centers." Presentation to NERC Large Loads Task Force, April 10, 2025. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/lltf/lltf_april_meeting___technical_workshop_presentations_.pdf.

Texas Legislature. 2025. "Planning Requirements for Large Loads." In Texas Senate Bill 6, 89th Legislature, Regular Session, enacted June 20, 2025, Sec. 2. https://legiscan.com/TX/text/SB6/id/3182174.

Vaidhynathan, D., K. Prabakar, G. Martin, A. Ramesh, B. Wheeler, C. Coco, and J. Clidaras. 2025. *Vulcan Test Platform: Demonstrating the Data Center as a Flexible Grid Asset*. NREL/TP-2C00-94844. National Renewable Energy Laboratory. https://docs.nrel.gov/docs/fy25osti/94844.pdf.

Wilson, J. D., S. Meyer, Z. Zimmerman, and R. Gramlich. 2025. *Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers*. Grid Strategies. https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies-National-Load-Growth-Report-2025.pdf.

Wiser, R. H., E. O'Shaughnessy, G. L. Barbose, P. Cappers, and W. Gorman. 2025. "Factors Influencing Recent Trends in Retail Electricity Prices in the United States." *The Electricity Journal* 38(4): 107516. https://doi.org/10.1016/j.tej.2025.107516.

Wood Mackenzie. 2025. *Load Growth on Utility Terms: A Comparative Analysis of Large Load Tariffs*. https://www.woodmac.com/news/opinion/large-load-tariffs-a-looming-challenge-for-utilities/.

Forecasting for Large Loads: Current Practices and Recommendations

A Report by the Energy Systems Integration Group's Large Loads Task Force

This report is available at https://www.esig.energy/large-loads-task-force/forecasting/.

To learn more about the ESIG Large Loads Task Force and the recommendations in this report, please send an email to info@esig.energy.

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

ESIG
ENERGY SYSTEMS INTEGRATION GROUP