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Get a Load of This

Regulatory Solutions to Enable Better Forecasting of Large Loads

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Authors and Acknowledgments

Authors

Jeffrey Sward
Lauren Shwisberg
Katerina Stephan
Jacob Becker

All authors are from RMI unless otherwise noted.

Contacts

Jeffrey Sward, jsward@rmi.org
Lauren Shwisberg, lshwisberg@rmi.org

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About RMI

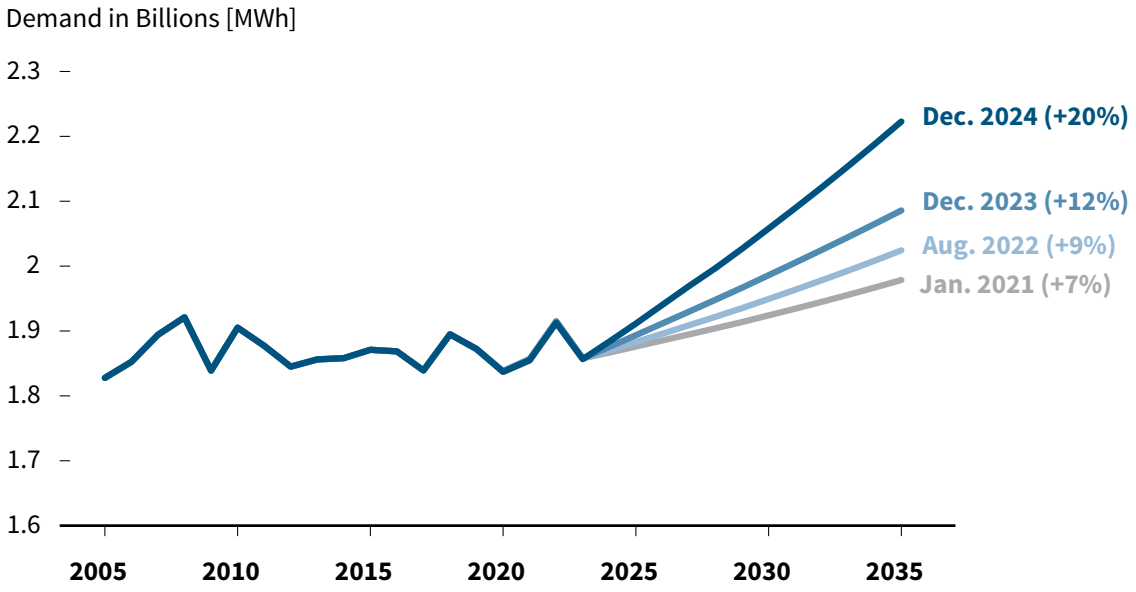
RMI is an independent nonprofit, founded in 1982 as Rocky Mountain Institute, that transforms global energy systems through market-driven solutions to align with a 1.5°C future and secure a clean, prosperous, zero-carbon future for all. We work in the world's most critical geographies and engage businesses, policymakers, communities, and NGOs to identify and scale energy system interventions that will cut climate pollution at least 50 percent by 2030. RMI has offices in Basalt and Boulder, Colorado; New York City; Oakland, California; Washington, D.C.; Abuja, Nigeria; and Beijing.

Table of Contents

Executive summary

In the United States, electricity demand, or load, has begun to grow following several decades without growth. Utility integrated resource plans (IRPs) from utilities covering 48% of sales to US customers expect load to grow 20% from 2023 through 2035, and utilities continue to make upward revisions in their load forecasts (see Exhibit ES1).

Exhibit ES1 Projected electricity demand (load) in IRPs



Note: Data includes projections from 121 IRPs, covering 48% of electricity delivered to US customers. The percent of change is for 2023 to 2035.

RMI Graphic. Source: RMI Engage & Act, https://rmi.org/our-work/climate-finance/engage-and-act/

Load forecasting is the process of predicting the time, location, and scale at which loads will materialize and how they will operate. This report focuses primarily on long-term (10-plus year) forecasts that utilities use for planning. Long-term load forecasts are the backbone of utility investment plans. The IRP forecasts in Exhibit ES1 are the basis for billions of dollars of proposed investments between 2023 and 2035, including 260 gigawatts (GW) of wind and solar additions, 84 GW of gas additions, and 74 GW of coal retirements, which are subject to regulatory approval.

Improving load forecasting can create two main benefits. It can:

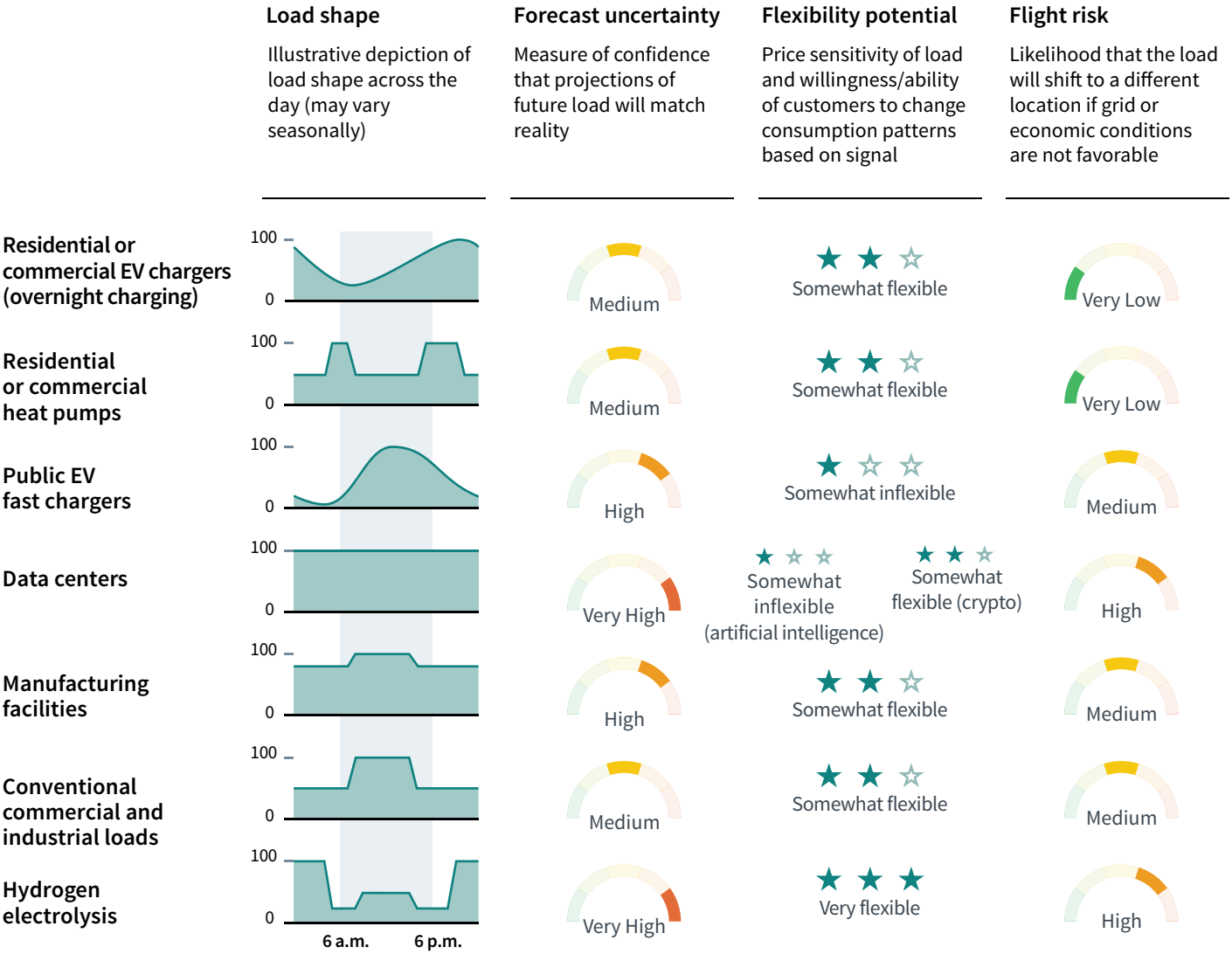
- Mitigate affordability and reliability risks. Good forecasting is the first line of defense in managing the major risks of systemic forecasting error. Customer affordability is the main risk of over-forecasting, and reliability is the main risk of under-forecasting.

- Create an opportunity to consider all available investment options. When utilities are caught off guard by under- or over-forecasts, investment options become more reactive and limited.

Given their rapid rise and massive capacities relative to existing systems, drivers of new large loads (e.g., data centers, advanced manufacturing, heavy transportation, industrial electrification) have unique characteristics that should be captured in modern forecasting processes: their load shape, forecast uncertainty, flexibility potential, and flight risk (see Exhibit ES2).

Exhibit ES2 Not all load is equal: key characteristics of how load types affect the grid can vary significantly

Key characteristics of how load types impact the grid can vary significantly



RMI Graphic. Source: RMI analysis

Forecasters can apply several best practices to improve forecasts regardless of the characteristics of coming loads:

- Employ scenario-based or stochastic load forecasting methods to better understand the range of possible futures and identify major sources of uncertainty, rather than relying on a single forecast to get it right.
- Integrate end-use forecasting with econometric forecasting to adjust forecasts based on economy-wide trends and historical data. This helps to more adequately capture the adoption and operation of loads that have not yet reached market saturation or do not correlate with typical macroeconomic indicators (e.g., electric vehicle [EV] adoption).
- Ensure load forecasts are used consistently across planning processes so that decisions in different processes are based on the same underlying set of data and assumptions.

Approaches to integrating new large loads into forecasts are nascent, with examples in regions that are projecting rapid growth, such as Georgia, North Carolina, and Virginia. New large loads exacerbate three major forecasting challenges, as depicted in Exhibit ES3.

Exhibit ES3 Goals for modernizing forecasts to integrate large loads

Challenges with load forecasts today	Goals for load forecasts
Limited: Load forecasts may not include the relevant characteristics of large loads.	**Thorough:** Ensure load forecasts accurately reflect the unique characteristics of large loads to their best ability.
Outdated: Load forecasts that are updated annually do not match the current pace of change.	**Up-to-date:** Increase the frequency of updating both load forecasts and load forecasting processes.
Opaque: Load forecasts can rely on inaccessible data, making bias tracking infeasible.	**Validated:** Make load forecast data and processes visible to other stakeholders and create opportunities for accountability.

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While utilities and grid operators develop forecasts, regulators have three critical roles with respect to forecasts: (1) establish guidelines for forecasting, (2) review and approve utility forecasts, and (3) ultimately approve or deny cost recovery for investments made based on forecasts.

Regulators can take several actions to align forecasts toward the goals in Exhibit ES4. These actions were informed by discussions with regulators, industry experts, and RMI staff in RMI's second Regulatory Collaborative (**Reg Lab**) cohort.[i]

Exhibit ES4 Actions for regulators

Goals for load forecasts	Actions regulators can take
Thorough	• Increase commission and utility understanding of new loads by initiating technical conferences or investigatory proceedings or by engaging informally with stakeholders. • Revise planning guidelines to incorporate emerging forecasting practices for new loads, such as establishing a separate large load forecast and processes to avoid double counting (see *Appendix: Discovery questions for load forecasting*). • Coordinate with state and local governments and other states to understand incentive structures and legislation that may affect large loads.
Up-to-date	• Require more frequent reporting of long-term load forecasts, such as quarterly. • Iterate forecasting processes as new practices and end uses emerge so that forecasts remain current.
Validated	• Encourage utilities to leverage transparent external data and forecasting tools where possible so that stakeholders and the commission can play an active role in vetting assumptions. • Make forecasts and actuals accessible and learn from past forecasts to assess past forecast accuracy and identify sources of error. • Explore monetary incentives or penalties for forecasts based on accuracy, including tariffs that shift risk to the specific large customers driving load growth or to the utility.

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i Reg Lab is a cohort-style initiative that builds regulatory staff capacity and develops cutting-edge solutions to today's pressing issues. Regulators from 15 states joined experts from across the country to explore near-term options to potential load growth in seven virtual workshops. For more information on previous and future cohorts, please see: **https://rmi.org/reg-lab/**.

Even when best practices are adopted, all forecasts remain uncertain. However, with rapid load growth projected, utilities and commissions must be able to make decisions despite significant forecast uncertainty. Regulators can refine their decision-making toolkit to mitigate the risks of forecast uncertainty. They can:

- Prioritize "least-regrets" capital investments, including investments that are currently fast, affordable, and flexible (e.g., energy efficiency, virtual power plants [VPPs], grid-enhancing technologies, reconductoring, and clean repowering) and that are robust and provide benefits under a wide range of possible futures (e.g., interregional transmission).

- Use tariff design or other contractual commitments to allocate risk and shore up uncertainty, by implementing tariff structures or rate changes that allocate some of the risk back onto large customers driving growth.

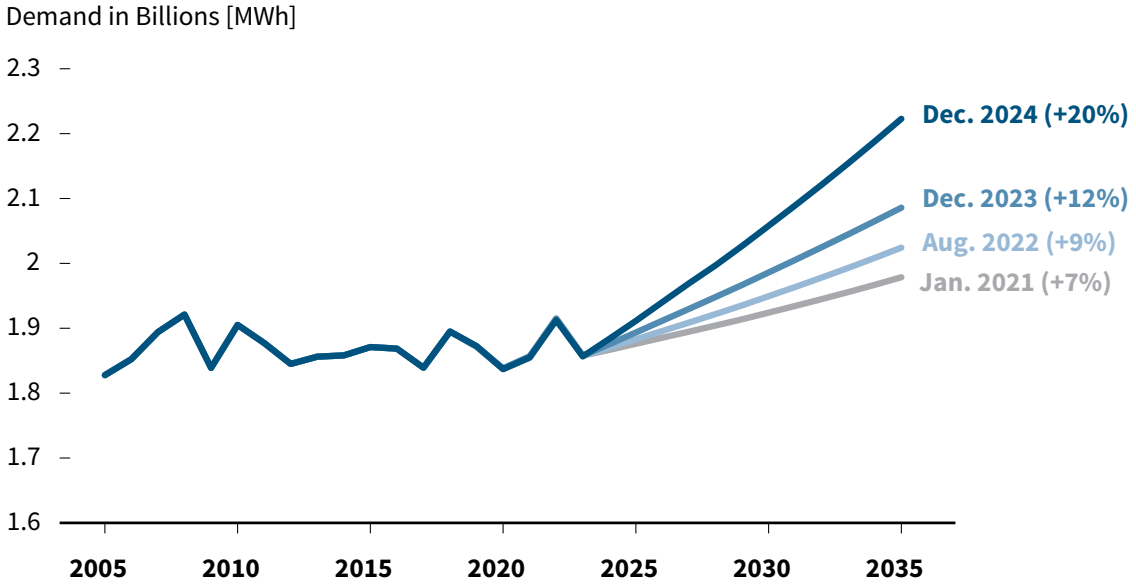
These actions are the first steps utilities and commissions can take to mitigate the affordability and reliability risks of forecasting, but there is a need for more research. More publicly available and easily accessible data characterizing the developmental timelines and operational patterns of these loads would improve forecasting accuracy. New research can help identify methods to better deconflict economy-wide forecasts and end-use forecasts and propose new processes that go beyond econometric modeling. Even though all forecasts are wrong, the scale of projected load growth and its potential risks create an imperative to ensure that forecasts remain useful in guiding consequential regulatory decisions.

Load is growing and projections are growing faster

Between 2022 and 2024, grid planners increased the five-year peak load forecast from 23 GW of projected new load to 128 GW.[1] As of December 2024, utility IRPs representing 48% of electricity sales in the United States expected load to grow 20% through 2035, up from 7% in January 2021.[2] Today's forecasts are flipping the classic North American Electric Reliability Corporation (NERC) fan upside down[3] — in place of consistent downward revisions in forecasts, utilities are currently making consistent upward revisions in forecasts (see Exhibit 1).

Exhibit 1

Projected electricity demand (load) in IRPs

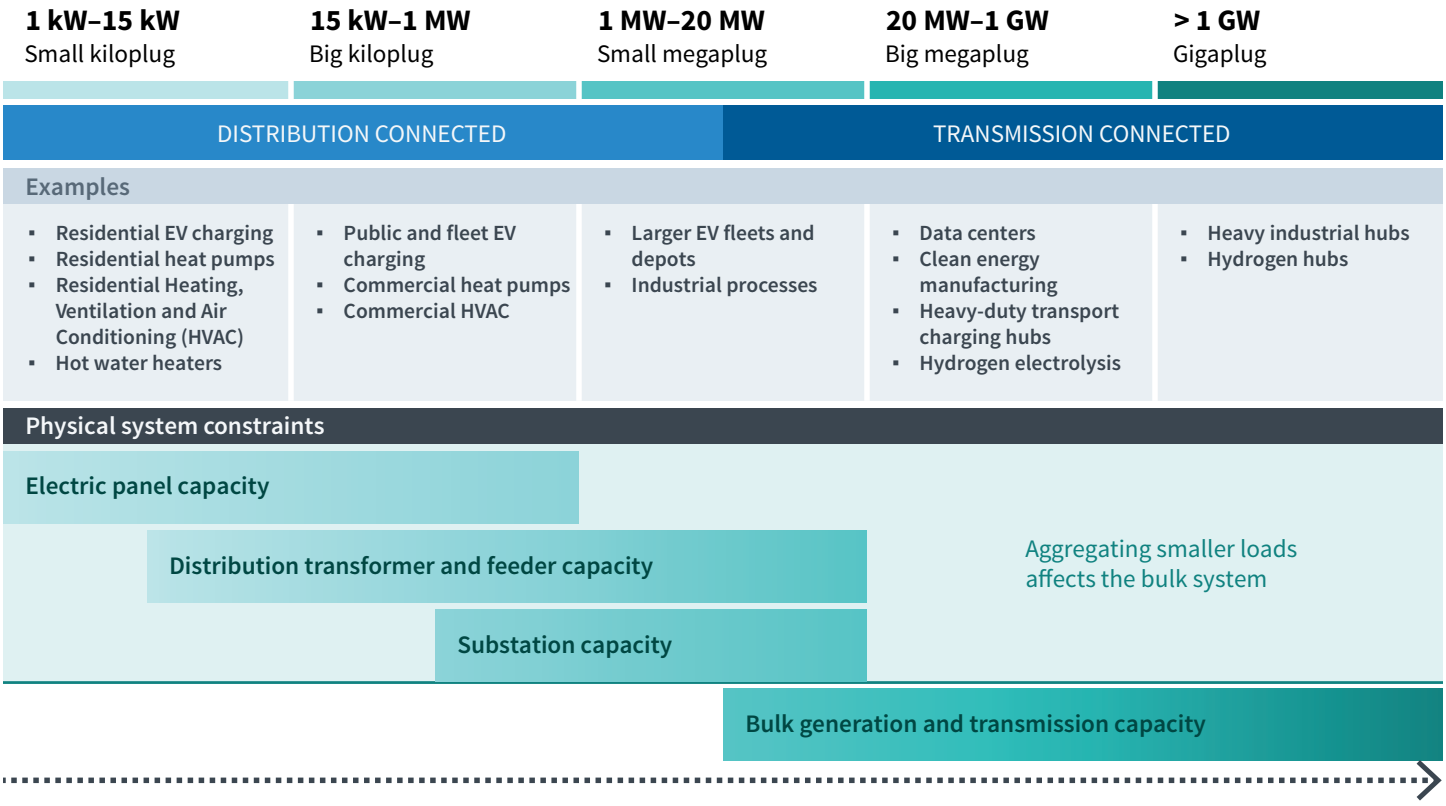


Note: Data includes projections from 121 IRPs, covering 48% of electricity delivered to US customers. The percent of change is for 2023 to 2035.

RMI Graphic. Source: RMI Engage & Act, https://rmi.org/our-work/climate-finance/engage-and-act/

From residential consumers to companies, electricity users of all sizes are seeking to connect to the distribution and transmission grids, driving that forecasted load growth. Exhibit 2 depicts the potential effects of load growth across all levels of the system. On the transmission system, the main drivers behind load growth include new manufacturing, industrial, and data center facilities as well as large-scale charging infrastructure for EVs. On the distribution system, EV charging and electrified heating are emerging as new demands and new resources. To support these distributed end uses, broader infrastructure upgrades deployed at scale are necessary. Given the many new end uses with unique characteristics compared with traditional end uses, forecasting approaches must advance so utility planning can keep the grid reliable and costs down.

Exhibit 2 **Load growth affects all levels of the grid**



RMI Graphic. Source: RMI analysis

Several types of load growth drivers are showing up in utility plans across the country, as summarized in Exhibit 3.[4] In the near term, data centers and advanced manufacturing represent the largest drivers of growth in the Southeast, the Rust Belt, and numerous tech hubs across the United States. Their large loads pose unique forecasting challenges for utilities and grid operators.

Exhibit 3 Near-term load drivers for 11 large utilities and independent system operators or regions

Near-Term Load Drivers	Data Centers	Manufacturing	Electrification
Arizona Public Service	✓		
CAISO	✓		✓
Duke	✓	✓	
ERCOT	✓	✓	
Georgia Power	✓	✓	
ISO-NE			✓
MISO	✓		✓
NYISO	✓	✓	✓
Pacific Northwest	✓	✓	
PJM	✓	✓	✓
SPP	✓		

RMI Graphic. Source: Grid Strategies, https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf

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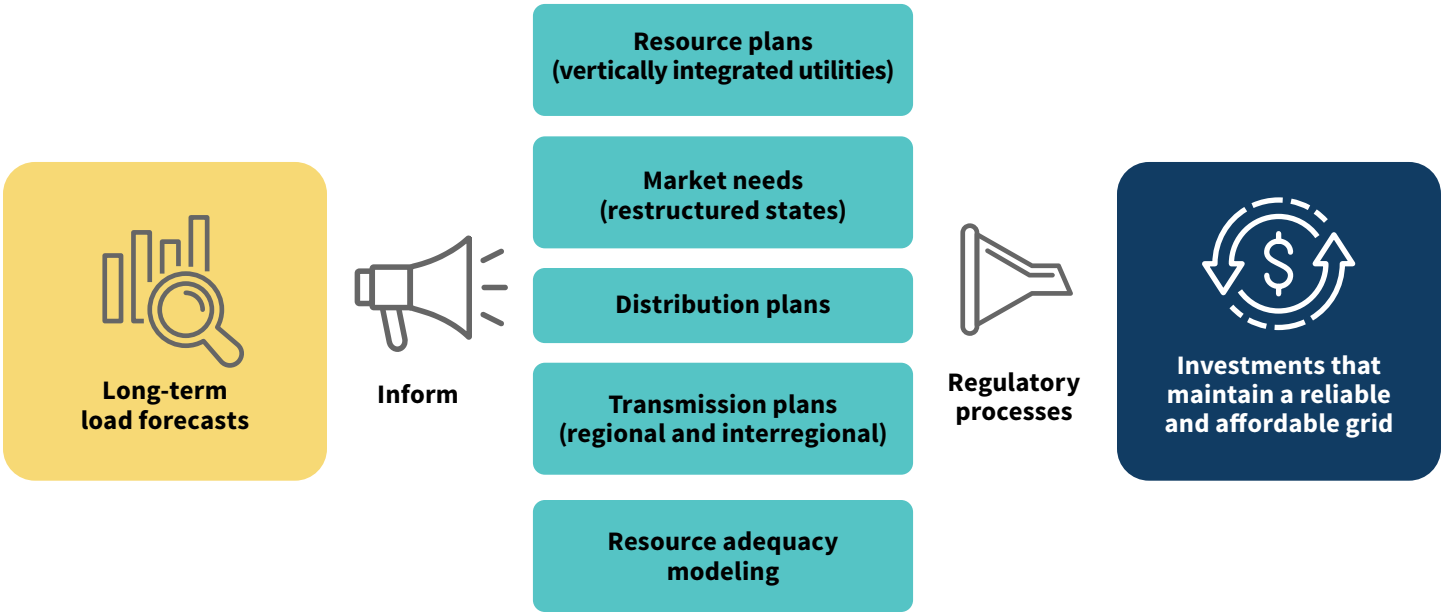
Load forecasting is the process of predicting the time, location, and scale at which loads will materialize and how they will operate. Utilities typically develop forecasts for multiple purposes across many time scales. These range from daily operational forecasts to quarterly sales estimates, to 10- to 20-year long-term planning forecasts.

This report focuses primarily on long-term forecasts that utilities use for planning. Long-term load forecasts form the backbone of resource plans that ultimately justify utility infrastructure investment decisions and affect the quality of electric service — that is, the ability to create and maintain a system that provides reliable energy, capacity, and grid services at a fair price for all customers. Utilities seek to forecast electricity needs, both total energy consumption and peak load, for each segment of their customer base, traditionally residential, commercial, and industrial. In addition to justifying a preferred portfolio of new generation resources, long-term load forecasts inform market needs for utilities in restructured states, distribution system upgrades, regional transmission upgrades, and resource adequacy modeling (see Exhibit 4). In addition, individual utility load forecasts often feed into regional transmission organization load forecasts that assess the need for bulk system transmission upgrades and interregional transmission.

Exhibit 4 Load forecasts influence key regulatory proceedings; however, the ultimate investment decisions must filter through regulatory processes and gain regulatory approvals



RMI Graphic

Accurate, frequent, and accountable load forecasts offer the first line of defense in mitigating the key risks that large load additions pose: affordability and reliability. Forecasts are used to justify billions of dollars worth of investments. As of December 2024, US utility resource plans had proposed 260 GW of wind and solar additions, 84 GW of gas additions, and 74 GW of coal retirements between 2023 and 2035.[5] Furthermore, in 2024, Edison Electric Institute projected that US investor-owned utilities would make a historic $168.2 billion in capital expenditures during 2025 alone.[6]

Despite these investments, a number of factors necessitate updated forecasting processes: the pace at which businesses would like to interconnect new loads compared with the speed of regulatory processes, the scale of these loads compared with existing utility service, the uncertainty in their timing, and their operational characteristics. While advanced forecasting practices have already begun to take shape for smaller distributed loads, emergent large load drivers have yet to be systematically integrated into many utility plans.[7] Backlogged interconnection queues, congested transmission systems, and increasingly frequent and severe extreme weather events further exacerbate reliability risks as load growth and retirements threaten to outpace the deployment of new generation.

Improving large load forecasts can broaden the set of options that utilities and regulators might consider to serve the load. When utilities are caught off guard by new loads, options become limited. Throughout 2024 this has become clear: forecasted load growth is currently resulting in utility commitments to options that are quick or familiar, such as delayed retirements and new gas proposals. These solutions are driving up forward-looking emissions estimates, increasing exposure to fuel cost risk, and denying the cost savings that would come from swapping older units for newer more efficient ones.

This report explores today's large load drivers, details how leading utilities and independent system operators are integrating large loads into their forecasts, and establishes a set of modern load forecasting best practices to aid regulators in navigating this new era of development.

Further reading

- For an exploration of the rapidly changing landscape of load drivers and how they complicate load forecasting for utilities and system operators, see ***Electricity Demand Growth and Forecasting in a Time of Change***, Brattle, May 2024.
- For a deep dive into recent load growth drivers, see ***The Era of Flat Power Is Over***, Grid Strategies, 2023.

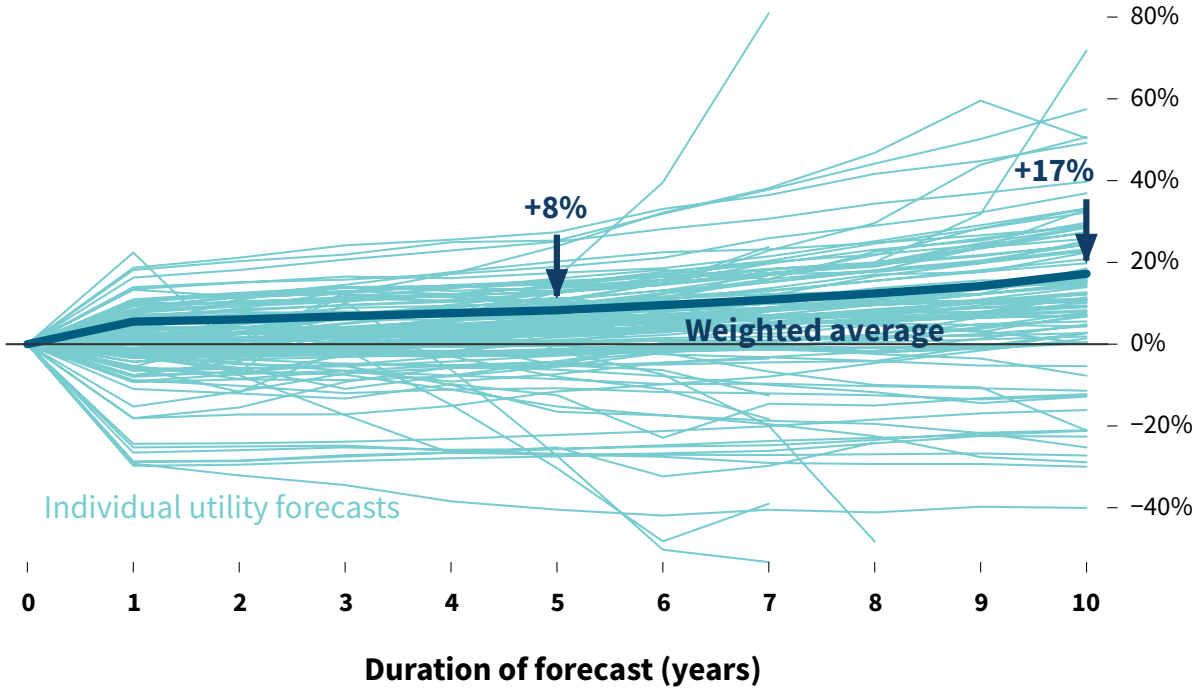
Regulators must seek to mitigate the risks of both under- and over-forecasting

In an ideal world, utilities would perfectly forecast load and regulators would have the confidence to approve proactive infrastructure investments that would save customers money over the long run. In reality, predicting the future accurately is challenging. As a result, regulators have a role to understand and mitigate the risks associated with load forecast errors.

Historical over-forecasting

Historically, utilities have systematically over-forecasted electricity demand, which indicates an opportunity to improve forecasting processes. Between 2006 and 2023, utility planners, on average, over-forecasted electricity demand by 8% in 5-year forecasts and by 17% in 10-year forecasts (see Exhibit 5). The forecast error is even higher for more recent years: data from 2012 to 2023 shows that forecasts were, on average, 23% higher than actuals.

Exhibit 5 **Electricity planning area peak demand forecast error 2006-23**



RMI Graphic. Source: RMI analysis of FERC Form No. 714 data

A 2017 RMI study that reviewed historical load forecasts highlighted three systemic factors that contribute to over-forecasting, all of which are relevant to today's challenges:[8]

1. Underestimating improvements in energy efficiency. Many utilities traditionally used a measure of energy consumption per customer, which has declined over the past several decades due to improvements in energy efficiency. Despite high energy intensity in large new data center loads, economy-wide energy intensity is expected to continue declining. Forecasters should strive to capture efficiency trends across sectors in both top-down and bottom-up modeling approaches.

2. Over-forecasting is more aligned with traditional utility incentives. For states without modernized utility business models, utilities are incentivized to build more infrastructure because they earn a rate of return on capital investments,[9] and this incentive is stronger if the allowed rate of return is higher than a utility's cost of capital. Although keeping rates affordable is a priority, specifically attributing rate increases to instances of over-forecasting is not straightforward.

3. Under-forecasting can lead to resource adequacy challenges for which utilities are accountable. In some cases, under-forecasting can lead to load shedding, brownouts, or blackouts during extreme conditions, which are felt acutely by customers. Furthermore, such resource adequacy issues have no simple solution. Leaning more heavily on both market purchases and emergency investments can create additional costs, which ultimately are borne by ratepayers.

The mismatch in the time required to permit and build new supply-side resources (as long as 10 years) and the speed at which some new large loads are ready to be interconnected exacerbates these dynamics. For example, data centers can be constructed far faster than traditional industrial facilities (i.e., they can come online within one to two years). However, because data centers turn over hardware on a two-year cycle, even if resource plans use the most up-to date hardware information, they will be several cycles behind by the time the planned resources arrive to meet the demand. Given that algorithmic efficiency for applications based on artificial intelligence (AI) remains a relatively new field, efficiency gains will likely be realized in the future both on software and in the underlying hardware.[10]

Risks from under- and over-forecasting and opportunities to mitigate them

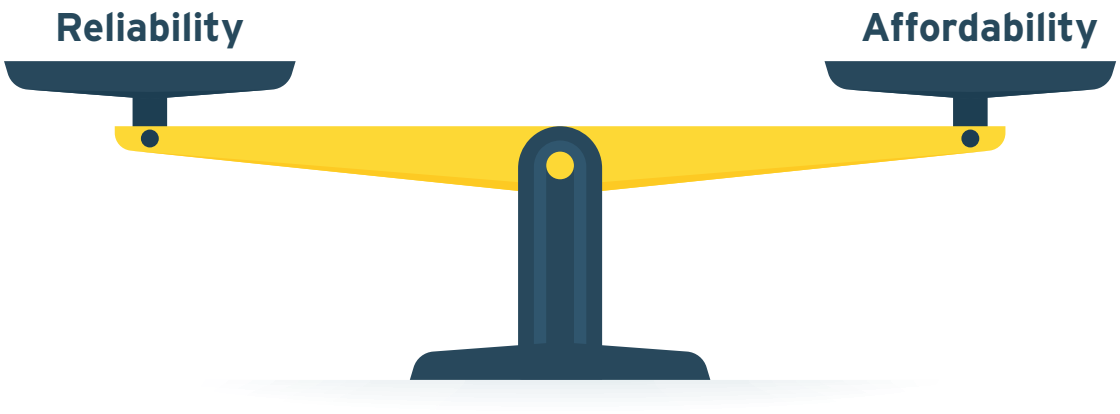
Forecasting is an opportunity to balance the risks of affordability and reliability, and either under-forecasting or over-forecasting can tip the scale (see Exhibit 6).

Under-forecasting primarily represents a risk to reliability and achieving policy priorities such as economic development, which affects utilities and their investors, policymakers, and customers. Furthermore, in restructured markets, insufficient capacity can increase customer bills, making them less affordable (e.g., consumers will pay $14.7 billion for capacity in PJM during the 2025–26 delivery year, up from just $2.2 billion in the 2024–25 delivery year).[11]

Customer affordability is the primary risk associated with systematic over-forecasting when it leads to over-investment. Some checks on this are embedded in the current regulatory paradigm, such as regulators' ability to withhold approval of investment until utilization rates of existing infrastructure meet a certain criterion. In some cases, prospective investments fail to pass a prudence review. Over-forecasting can also shift focus or funding toward system expansion and away from maintenance. With 70% of transmission lines more than 25 years old and approaching the end of their typical life span,[12] maintenance investments in the existing system are increasingly critical.

Exhibit 6

Load forecasting is an exercise in balancing reliability and affordability



RMI Graphic

Load characteristics critical for forecasting

New loads come with unique characteristics and timing that are important to reflect in forecasts because they change the options for future resource investment. Following is a framework highlighting specific load characteristics that can aid planning discussions about load growth.

Whereas load growth affects all levels of the grid, the effect of an individual load depends on several defining characteristics (see Exhibit 7).

- **Load shape:** Loads that operate during peak times or that are concentrated within a season where they coincide with many other loads are more likely to require grid upgrades or new generation. How the load will change over time, including whether there is a ramp-up period to full operation, can unlock additional resource options.

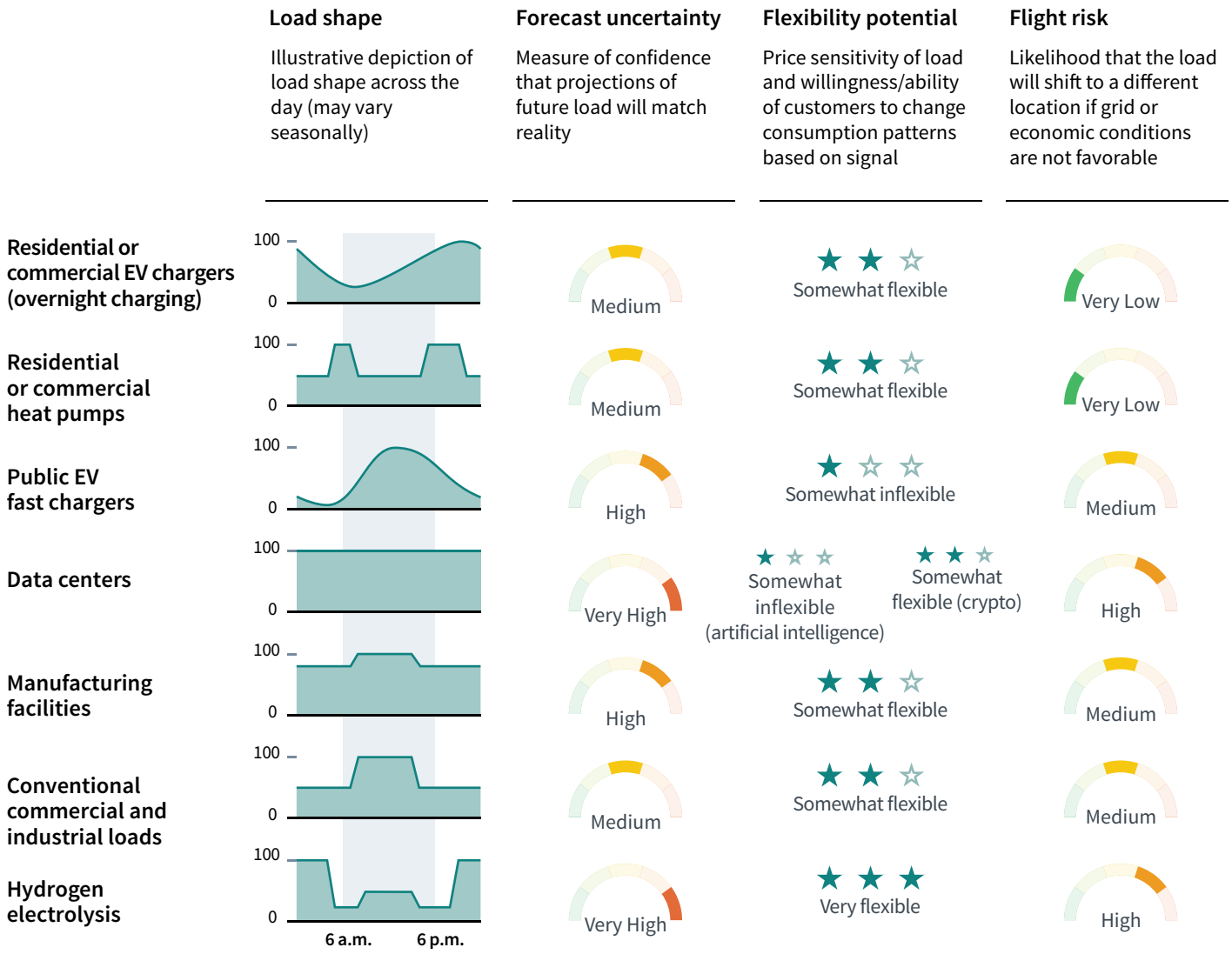
- **Forecast uncertainty:** How accurately loads can be projected into the future depends on weather, economics, customer behavior, and variations in device program offerings and defaults. Weather and customer behavior are difficult to predict accurately, leading to uncertainty in forecasts looking hours or days into the future, let alone years.

- **Flexibility potential:** Many more loads need to be connected to the grid, but a grid where all loads operate at the same time exacerbates emissions and cost challenges. Ideally, new loads drivers operate flexibly and pay more for drawing power during times of stress on the grid. Knowing the level and timing of flexibility that a load can offer can reduce the required generation capacity or can be used to design new flexibility incentives or programs.

- **Flight risk:** All businesses need electricity. Some need tons of electricity. Some require cheap power. Many need a skilled workforce nearby. These dynamics influence where load drivers choose to connect in the first place and the likelihood that changing market or economic conditions may convince them to contract or expand existing operations or shift new operations elsewhere.

Exhibit 7 Not all load is equal: key characteristics of how load types affect the grid can vary significantly

Key characteristics of how load types impact the grid can vary significantly



RMI Graphic. Source: RMI analysis

The old, the new, and the revived — deep dives into large electricity load end uses

New large loads in particular present a challenge to forecasters. This section details the characteristics of two of these large loads: data centers and industrial and manufacturing loads.

Data centers

Data centers are a well-established end use made relevant by the recent rise in power-hungry large language models and proof-of-work cryptocurrency mining. Load growth from data centers is expected to be geographically uneven, which may present local challenges as 15 states currently account for 80% of the national data center load. For example, data centers are estimated to comprise 25.6% of Virginia's electric load in 2023, and higher growth estimates predict that share increasing to 46% by 2030.[13]

Load shape and flexibility potential

There are several types of data centers, each with unique flexibility considerations. A 2024 white paper by the Electric Power Research Institute (EPRI) synthesizes several different data sources to depict geographic hot spots of data centers by type.[14] Multitenant or colocation data centers (those shared or leased by multiple organizations in the same physical location) guarantee extremely reliable service to their customers. A Tier I data center (the lowest tier) aims for 99.671% uptime, which translates to just 28.8 hours of downtime per year.[15] As such, multitenant data center providers plan and operate with minimal to no flexibility, aiming for as close as possible to a constant 100% load factor.

In contrast, data centers owned and operated by individual tech companies may have greater flexibility potential because they have fewer client-driven constraints. For example, Google is running a pilot to determine how best to participate in demand-response programs with its data centers.[16]

Cryptocurrency mining operations frequently operate flexibly because they are more price sensitive, but their participation in flexibility programs has drawn controversy due to payments from demand response exceeding revenue from their core business.[17] Mining operations can exacerbate emissions while also increasing local noise and air pollution.[18] Furthermore, in-depth analysis by the US Energy Information Administration concludes that there is major uncertainty surrounding the energy consumption of cryptocurrency mining,[19] making analysis of flexibility potential for this segment even more challenging.

Forecast uncertainty and flight risk

Load growth from data centers carries perhaps the highest forecast uncertainty of any relevant large end use today. Excitement surrounding generative AI is driving the current data center boom, but if long-term business models fail to turn a profit or if hardware and software advances moderate the amount of power demanded from the industry, data centers come with a risk of stranded assets and abandoned contracts. In the near term, however, there has been enough investment to develop a substantial number of new data centers, as already experienced in Northern Virginia.

A range of tariffs for large loads is emerging, including some explicitly for data centers, which can help mitigate forecast uncertainty and flight risk.[20] Tariffs that help mitigate uncertainty do so through mechanisms such as a contracted maximum demand, which is the maximum demand the load is allowed to reach under the contract and includes specified ramp times to reach that demand. See ***Actions regulators can take to improve forecasting*** (page 31) for more on tariff design and additional options to address these concerns.

Data centers have no strict land use requirements and therefore can be sited essentially anywhere with solid infrastructure (e.g., power, fiber, water, roads), which contributes to siting location uncertainty. However, some data centers may seek to colocate with generation to reduce transmission and distribution costs or emissions.[21] Data center companies often approach multiple utilities to negotiate the most favorable contract price and terms. In response, many states have created tax breaks for data centers as part of a broader economic development policy.[22] Although the long-term employment benefits provided by data centers are minor, personal property and real estate taxes on the equipment within them can create a tax windfall, especially in smaller economies.[23] These incentives initially made it simpler to predict where data centers might locate, but with headroom on existing grids now limited in primary markets, forecasting uncertainty will likely increase.

Many data center companies (e.g., Google, Amazon, Meta, and Microsoft) have voluntary climate pledges. This has encouraged them to seek tariffs and other novel arrangements that provide them with clean generation to cover their demand. For example, Google signed a clean transition tariff with NV Energy and Fervo,[24] and Microsoft signed a power purchase agreement with Constellation Energy to restart Three Mile Island.[25] Such agreements can include longer term lengths than traditional tariffs, providing utilities and asset owners greater confidence that their long-term investments will remain relevant.

Communication among states, improved zoning laws, and financial commitments from prospective data center developers can provide more certainty to load growth projections. Data centers remain subject to state and local commercial zoning laws. Therefore, cities and states can preferentially push them to brownfield and greyfield areas, which may be eligible for the Energy Infrastructure Reinvestment program,[26] thereby reducing the set of possible development locations.

Further reading

- For an exploration of present utility understanding and leading practices in addressing data center service requests, and integrating those requests into planning and operation processes, see ***Utility Experiences and Trends Regarding Data Centers: 2024 Survey***, EPRI, 2024.

Industrial loads and manufacturing

For the first time in a generation, manufacturing is returning to the United States rather than moving offshore.[27] This reshoring has been driven primarily by new industries that have sprung up in response to the clean energy transition and has been supercharged by Inflation Reduction Act incentives.[28] Because many industrial facilities operate large machines at high load factors, they hold opportunities to provide load flexibility and grid stabilization services.

Load shape and flexibility potential

Industrial loads often have the most "classic" load shape, following the shifts of workers. In other words, shifts staffed by more workers experience higher electrical demand. As the industrial sector electrifies, process heat requirements may keep load factors elevated outside of business hours. However, new industrial electrification technologies could provide ample opportunities for load flexibility.[29]

Such loads often display some flexibility, which helped make possible early utility demand-response programs. With the scope and value of demand-response programs expanding, utilities can continue to partner with industrial customers on demand-response programs, as their proven track record provides confidence in this resource. Furthermore, if green hydrogen becomes more established, it would offer a nearly ideal industrial process to participate in demand response due to its price sensitivity. Electricity contributes 50% to 70% of the levelized cost of hydrogen production.[30]

Forecast uncertainty and flight risk

Industrial customers tend to have low forecasting uncertainty because siting and permitting industrial facilities requires substantial time.[31] This generally means that once an industrial facility opens its doors, it is less likely to strand electrical infrastructure assets built on its behalf. Briefly, industrial sites generally require:

- Access to sufficient, correctly zoned land
- A location that can pass environmental reviews and receive community approval
- Supporting infrastructure for shipping raw materials and finished products (or the ability to create such infrastructure)
- A skilled local workforce
- Economic development tax credits
- Cheap electricity or economic development rates (which are often required for a project to turn a profit, for example, hydrogen production via electrolysis)
- High-capacity interconnections that often require distribution upgrades and sometimes require transmission upgrades

Given their price sensitivity, industrial customers may be able to strategically colocate near cheap clean resources if other requirements can be met. For example, the Evraz Rocky Mountain Steel mill in Colorado recently constructed an on-site solar facility to reduce net load.[32] Whereas historically most industrial processes have used fossil fuels to produce process heat, industrial heat pump technologies are beginning to mature, so seeking out cheap clean electricity could give industrials a competitive edge.

Load forecasting best practices

Prior to recent excitement surrounding large loads, a set of forecasting best practices had already been articulated. These best practices are now even more important for utilities to implement. Below is a summary of best practices from several resources.[33]

Employ scenario-based or stochastic load forecasting methods. When fewer end uses required electricity, both generation resources and loads were less weather dependent and less flexible, so that using a single deterministic forecast was sufficient. Long-term planning forecasts that drive investment decisions should consider multiple futures.

- Communicate load forecasts as ranges rather than single values. Taking a median scenario (or any single scenario) can obscure the value provided by stochastic methods, which are designed to encourage planners to consider a variety of risks, their likelihoods, and how they can affect load growth. Such ranges can better inform downstream modeling (e.g., resource adequacy studies) as well as allow regulators to view a more nuanced picture, which can help elucidate the difference between required, least-regrets, proactive, and imprudent investments.
- Attach reasonable probabilities to each scenario. Given the uncertainty and speculation surrounding large loads, utilities may choose to focus attention on a high load scenario and implicitly assign a higher probability to such a scenario. Planners should clearly communicate the likelihood of scenarios or ranges.
- Identify sources of load forecasting uncertainty. Not all uncertainty affects the forecast in the same way. For example, weather-related uncertainty may be accounted for in downstream resource adequacy modeling. On the other hand, a prospective data center customer that is still exploring siting across different utilities to identify the most favorable location represents a potential large step change in future load — and therefore could be treated via a scenario associated with a tailored probability.
- Incorporate scenarios that consider deviant policy and economic conditions. Although contingency planning can help hedge against unexpected events (e.g., the war in Ukraine), scenarios considering state and federal policy changes as well as economic cycles can help hedge against conditions that might be unlikely but would have a long-term impact.
- Include future climate data as well as historical weather data. This helps to capture a more complete — and therefore more realistic — distribution of future weather conditions (e.g., First Street Foundation's flood map projects much higher risk in Asheville, North Carolina, using future climate data than the Federal Emergency Management Agency's flood map, which uses historical data).[34]
- Employ long time horizons for planning forecasts to capture medium- and long-term trends (i.e., 10-plus years). However, recognize that forecast skill decreases further into the future.

Integrate end-use forecasting with econometric forecasting. Adoption patterns for both emerging and incumbent technologies will be more accurately forecasted with technology-specific models.[35] Models for individual end uses can ladder up to the area-wide stochastic planning forecast and may include their own stochastic elements. However, any hybrid methodology must protect against double counting, which could occur if adjustments are made for new load without accounting for their representation in econometric projections.

- Develop bottom-up 8760 load profiles for key end uses that have not reached market saturation or do not yet correlate with typical macroeconomic indicators. Whereas some incumbent end uses (e.g., residential refrigeration) have reached market saturation so that end-use modeling would not provide additional value, adoption and operation patterns of emergent end uses (e.g., EVs and heat pumps) carry substantial uncertainty. Furthermore, developing load profiles that track key large load customers (e.g., data centers or manufacturing facilities) can aid in retrospective analyses and offer a way to improve future forecasting assumptions.

- Perform separate forecasts for adoption, operation, and flexibility. Projecting adoption and operations for emergent end uses as well as large customers is commonplace at some utilities.[36] Forecasting flexibility more granularly and integrating such forecasts into downstream modeling practices (e.g., resource adequacy) remains an area for improvement.

- Incorporate newly available or underused data. Historically, regression algorithms provided a state-of-the-art forecasting tool for utilities. While regression still performs well in some applications today, AI algorithms may offer a better set of tools to capture complex trends in data and thereby improve forecast skill. This could allow utilities to leverage diverse data streams such as smart home device feeds, vehicle telematics, gas usage, weather reanalysis, local climate, customer propensity, and more to create differentiated forecasts for adoption, operation, and flexibility for a variety of end uses and large load customers.

- Track ongoing local adoption of various end uses to improve end-use models. Utilities can partner with smart home providers, VPP aggregators, large load customers, and local governments, which each hold a piece of puzzle depicting current adoption trends. Regulatory or policy action may aid in making such data available to utility planners.

- Seek direct customer input on forecasts. Particularly for large loads, including manufacturers, data centers, and EV fleets, additional engagement can lead to better outcomes on both sides. In addition, frequent input coupled with retrospective analyses can create a cycle of accountability between utilities and large load customers that may give regulators greater confidence in forecasts of these customers.

- Benchmark against third-party forecasts. Many independent organizations conduct end-use forecasts. For example, EPRI's EVs2Scale predicts adoption patterns for both light- and heavy-duty EVs,[37] and the National Renewable Energy Laboratory's ResStock and ComStock datasets provide end-use profiles for the US building stock.[38]

Ensure load forecasts are used consistently across different planning processes. Utilities should use consistent data and assumptions for load forecasts at all levels of planning — budget planning, distribution system planning, transmission planning, integrated resource planning, resource adequacy assessments, and contingency planning — or explain why and how their load forecasts differ. Although using a single forecast carries the benefits of internal consistency, it also exacerbates the impact of any forecast errors.

Further reading

- For an overview of and best practices associated with developing forecasts, including forecasting of utility load, energy efficiency, demand flexibility, building electrification, EVs, distributed solar, distributed battery storage, and utility costs, see **Developing Forecasts: Basics & Best Practices**, Lawrence Berkeley National Lab, 2023.

Case studies: Emerging practices for forecasting large loads

Although no utility's load forecasting process can serve as a model today, recent developments in locations where load forecasts have grown fastest hold important lessons. They also elucidate the role of regulatory staff, large load customers, and other intervenors in improving forecast accuracy. This section explores recent dockets from Dominion Energy in Virginia, Duke Energy in North Carolina, and Georgia Power.

Case study

Dominion Energy in Virginia Proceedings

General forecasting method

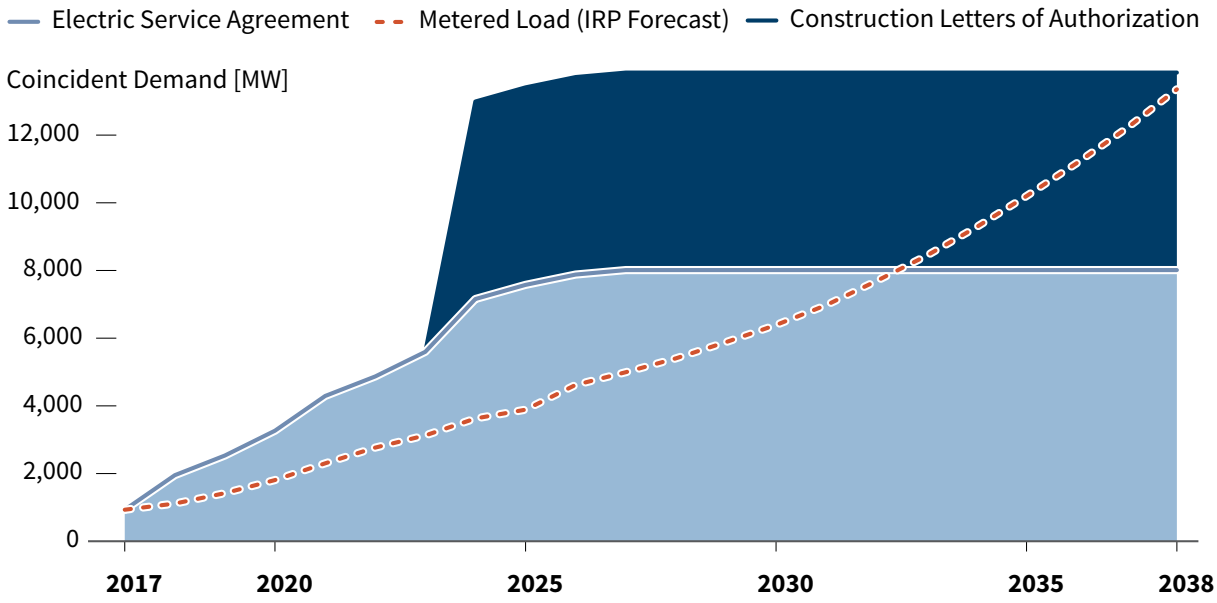
Dominion Energy uses an econometric approach to forecast sales, energy, and peak demand over a 15-year horizon.[39] The sales forecast produces monthly values by customer class, and breaks out estimates for heating load, cooling load, and non-weather-sensitive load. Appliance saturation and usage levels are dynamically adjusted in the residential forecast based on historical trends. The energy forecast is derived from the sales model using a simple regression that captures the historical relationship between monthly sales and energy consumption.

Historically adjusted hourly loads inform the hourly peak load forecast. This adjusted load excludes data centers but adds load offset by distributed solar generation and retail choice. The peak load forecast begins by predicting the non-weather-sensitive base demand; it then utilizes several weather variables — temperature, humidity, wind speed, cloud cover, and precipitation — to predict weather-sensitive demand. Additional variables capture variability on daily and seasonal time scales, and account for extreme or unusual events (e.g., hurricanes or the COVID-19 pandemic). Finally, adjustments for data centers, distributed resources, retail choice, and EVs are made at the end.

Data center forecast method

Dominion has made refinements to its data center load forecast over the years (see Exhibit 8). It first identifies the largest or fastest growing data center customers within its service territory — eight such customers in the most recent iteration — and then combines all remaining data center customers into an additional "customer." Second, it forecasts the load for each customer via statistical methods (i.e., linear regression) using a mix of public and confidential customer data. These customer forecasts are combined into an overall forecast, which represents the "high load" scenario. Dominion uses historical metered data to develop a statistical model of the data center industry, which it uses as its "low load" scenario. Finally, it averages the two scenarios to derive the "medium load" scenario, which it submits to PJM.

Exhibit 8 Data center contracted capacity vs. metered coincident demand in Dominion Energy's service territory



Note: Dominion did not review ESAs prior to 2018 and assumed ESAs were equal to actual demand in 2017. Actual ESA totals will be higher than this assumption.

RMI Graphic. Source: Dominion Energy, https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/company/irp/2024-irp-w_o-appendices.pdf

While Dominion's 2024 IRP is still under review by intervenors and the commission, its 2023 IRP update is instructive.[40] Virginia commission staff's consultants pointed out that load growth forecasts from PJM and Dominion were newly optimistic; forecasted data center load growth was higher than actual load growth for all of ERCOT.[41] Furthermore, a mere five companies made up 80% of the total projected data center growth through 2030. In other words, a slight shift in strategy by any of these companies could meaningfully alter realized demand in Dominion's territory. As a final note, the staff's consultants cautioned that forecasts should not only take into account future expected economic conditions but also seek to understand the rate of load realization (e.g., how much data center load is actually being built) versus forecasts.

Case study

Duke Energy in North Carolina Proceedings

General forecast method

Duke Energy's recent long-term load forecast was developed within its consolidated Carbon Plan and Integrated Resource Plan (CPIRP).[42] The forecast began with a service area–wide economic forecast from Moody's. Duke then produced an energy forecast using a statistically adjusted end-use model using key features, including income, electricity prices, industrial production indices, weather, and appliance saturation trends. Ex-post modifications to the forecast accounted for growth in EVs, rooftop solar, and energy efficiency programs. Finally, Duke derived summer and winter peak demand forecasts from the energy forecast.

Duke is also developing an integrated system and operations planning framework to enhance its load forecasting.[43] It includes Morecast, which is a 10-year hourly distribution system forecast focused on electrification, and third-party energy intensity forecasts. Currently, Morecast integration into IRP processes is still in development.

Large load forecast method

While economic growth is part of the baseline projection included in the economic forecast derived from Moody's, Duke manually applied an economic development adjustment for the first time in the 2023 CPIRP. This adjustment accounted for specific advanced-stage economic development projects in Duke's service areas absent in previous forecast cycles (e.g., data centers). To avoid double counting these projects with growth predicted by the econometric model, Duke reduced the projected load expectation on a by-project basis, typically by 30% to 60%.

According to testimony accompanying the CPIRP,[44] two main criteria were used to identify projects for the economic development adjustment: (1) either a prospective large load customer had already executed an agreement indicating an intention to obtain service from Duke or one was in an advanced stage of engagement toward that end, or (2) a prospective large load customer had begun physical development activities within Duke's territory (e.g., obtaining land, initiating rezoning of land). For the spring 2023 load forecast used in the initial 2023 CPIRP, Duke identified eight economic development projects. By the fall 2023 update, an additional 27 projects met the criteria. Given this rapid explosion of prospective projects, Duke developed an additional economic development load forecast for fall 2023 that included other known large projects that had yet to make material commitments.

The North Carolina Utilities Commission approved a stipulated agreement between Duke and other parties, which placed additional requirements on Duke's load forecasting practices.[45] In the stipulation, Duke agreed to monitor economic development and the large load pipeline and update the commission on its findings semiannually. Methodologically, the stipulation requires further discussion on predictive methods around uncertainty, greater consideration of distributed energy resources through customer programs and Grid Edge (a building energy efficiency management software), and consideration of grid-enhancing technologies.

Case study

Georgia Power

General forecast method

Georgia Power engages in full IRP proceedings every three years. A 2023 IRP update was approved in April 2024,[46] but the baseline forecasts associated with the 2022 IRP are the most recent general forecasts.

Georgia Power performs short- and long-term forecasts for both energy sales and peak load. At a high level, the short-term forecasts are econometric, feeding economic and demographic variables into a regression-based model. Historical weather data between 1980 and 2020 is averaged to define a normal weather year for forecasting, which neglects historical extremes and does not reflect the potential for different, more extreme future weather.

The long-term forecast has a 20-year horizon, driven by the IRP statute. The long-term forecast employs end-use models (LoadMAP from Applied Energy Group), which predict the uptake of various technologies and generate long-term forecasts by customer class. Finally, the resulting short- and long-term models are combined to produce the final forecast, with the short-term forecast used for the next 3 years and the long-term forecast used for the remainder of the 20-year period.

Large load forecast method

Georgia Power also forecasts rapid load growth, primarily from data centers and clean manufacturing. In its 2023 IRP update, the company significantly adjusted its forecast from its 2022 IRP due to the potential for large load additions. As part of this update, it established a methodology for integrating known project inputs into its forecast. Although Georgia Power had incorporated large loads in its forecast for prior plans to account for known large industrial projects, its 2023 IRP update filing represented a significant expansion of this process.[47]

Intervenors highlighted several opportunities for improving Georgia Power's large load forecast:

- Strengthening the commitment requirements for loads to be included in the forecast: Microsoft, in intervenor testimony, pointed out that that Georgia Power is unique among its peers in including large projects that have yet to select a location and a service provider, which could lead to overestimates of new large loads.[48]

- Using a broader range of forecasts in modeling: Microsoft and several other intervenors commented that the use of the P95 load forecast (representing the 95th percentile load forecast produced by Monte Carlo simulations) may be reasonable for a high-growth scenario, but not as the only forecast used for modeling in the 2023 IRP update.

- Increasing transparency: The commission's Public Interest Advocacy Staff commented that greater transparency is necessary — especially into ramp rate and load materialization assumptions — to determine the quality of the large load forecast. Additionally, some intervenors commented that confidentiality of prospective loads in the economic development pipeline shifts risk away from companies that may drop out of the pipeline with few consequences.

Although the Georgia Public Service Commission ultimately approved the forecast in the IRP update, it included a caveat that the approval does not constitute approval of the methodology used to create the load forecast. Furthermore, it directed Georgia Power to file quarterly large load updates to aid in the 2025 IRP.[49]

Georgia Power now files quarterly updates on its load forecast, including its economic development pipeline. These pipeline updates include:

- The total pipeline size

- Any changes in the pipeline from the previous quarter (e.g., projects entering or exiting the pipeline, construction updates, and new load announcements)

- Projected load ramp-up schedules

- Individual project information (e.g., customer class and market segment)

As of September 2024, the full economic development pipeline stood at 36.5 GW through the mid-2030s.[50] Information from this economic development pipeline is expected to flow into Georgia Power's load realization model, one component of its long-term load forecast process.

Actions regulators can take to improve forecasting

Regulators can play three critical roles with respect to forecasts: (1) establish guidelines for forecasting, (2) review and approve utility forecasts, and (3) approve or deny cost recovery for investments made based on forecasts. Although utilities are ultimately responsible for developing the forecasts, regulators can influence the quality and applicability of forecasts across different venues. While no forecast is perfectly accurate, ideally, forecasting processes are useful in guiding consequential regulatory decisions.

Regulators across both restructured and vertically integrated markets can focus on three goals to support more useful forecasting practices in the face of the challenges presented by large new loads (see Exhibit 9).

Exhibit 9

Goals for modernizing forecasts to integrate large loads

Challenges with load forecasts today	Goals for load forecasts
Limited: Load forecasts may not include the relevant characteristics of large loads.	**Thorough:** Ensure load forecasts accurately reflect the unique characteristics of large loads to their best ability.
Outdated: Load forecasts that are updated annually do not match the current pace of change.	**Up-to-date:** Increase the frequency of updating both load forecasts and load forecasting processes.
Opaque: Load forecasts can rely on inaccessible data, making bias tracking infeasible.	**Validated:** Make load forecast data and processes visible to other stakeholders and create opportunities for accountability.

RMI Graphic

The following subsection explores each of these goals and provides specific actions regulators can take to advance these goals for load forecasts (see Exhibit 10). The goals and actions were informed by discussions with regulators, industry experts, and RMI staff in the second **Reg Lab cohort**. We hope that by providing a menu of options to choose from or build on, states can more comprehensively improve load forecasting to meet today's challenges.

Exhibit 10 Actions for regulators

Goals for load forecasts	Actions regulators can take
Thorough	• Increase commission and utility understanding of new loads by initiating technical conferences or investigatory proceedings or by engaging informally with stakeholders. • Revise planning guidelines to incorporate emerging forecasting practices for new loads, such as establishing a separate large load forecast and processes to avoid double counting (see *Appendix: Discovery questions for load forecasting*). • Coordinate with state and local governments and other states to understand incentive structures and legislation that may affect large loads.
Up-to-date	• Require more frequent reporting of long-term load forecasts, such as quarterly. • Iterate forecasting processes as new practices and end uses emerge so that forecasts remain current.
Validated	• Encourage utilities to leverage transparent external data and forecasting tools where possible so that stakeholders and the commission can play an active role in vetting assumptions. • Make forecasts and actuals accessible and learn from past forecasts to assess past forecast accuracy and identify sources of error. • Explore monetary incentives or penalties for forecasts based on accuracy, including tariffs that shift risk to the specific large customers driving load growth or to the utility.

RMI Graphic

GOAL
Thorough

Ensure load forecasts accurately reflect the unique characteristics of new load drivers

Understanding and integrating the unique characteristics of new load drivers and modernizing forecasting processes can reduce unnecessary inaccuracy in load forecasts. Emerging large loads have unique characteristics that distinguish them from past end uses and from one another. Forecasts that are blind to characteristics including flexibility potential and flight risk will not reflect the needs of the future grid.

Options for regulators

Increase commission and utility understanding of new loads and their characteristics: Regulators can proactively learn about potential large load drivers in their state to better understand and evaluate forthcoming utility forecasts and other proposals, such as new tariffs. In addition to attending conferences, regulators can launch their own investigatory proceedings, technical conferences, or informal learning calls to increase their understanding of new loads specific to their state context. For example, the Minnesota Public Utilities Commission focused its external planning meeting in late 2024 on data center development in the state, with presentations and questions and answers from data center representatives, system planners, state agencies, and other stakeholders.[51] Similarly, when faced with challenges, including the impact of new loads on the electric system, the Maryland Public Service Commission initiated a technical conference on resource adequacy, with policymakers, experts, and other industry stakeholders providing specific recommendations.[52]

Revise planning guidelines to incorporate emerging forecasting practices for large loads: Regulators can set expectations or update guidelines for how utilities include new large loads in forecasts. Depending on where utilities are in their planning cycle, regulators can proactively set guidance by revising and updating planning rules or issuing orders on a previously filed plan or rate case to require future forecasting improvements. Guidelines could include one or more of the best practices described in the ***Load forecasting best practices*** section of this report.

Such new guidelines can better capture the characteristics of potential large loads. For example, regulators can request that load forecasts include the time each large load is expected to take to ramp up to contracted capacity, each load's flexibility characteristics, and the probability each will be built. Georgia commission staff took early steps and required the utility to file quarterly large load updates, which included the project status and expected ramp up period for each potential load.[53] Georgia Power's load forecasting process is discussed in detail in ***Case study: Georgia Power***.

In addition, regulators may need to update load forecasting practices to prevent double counting. If utilities create a separate large load forecast, regulators can request that utilities deconflict their large load forecast and their base economic forecast. Regulators can set expectations or ask detailed discovery questions to ensure that utilities discount econometric forecasts to account for large loads showing up in dedicated forecasts (see ***Appendix: Discovery questions for load forecasting***). For example, the State of North Carolina Utilities Commission directed Duke to monitor economic development and discount expectations of large load projects to avoid double counting of these loads and to explicitly account for such uncertainty as project delays, cancelations, and other factors outside Duke's control.[54]

Coordinate with state and local governments and other states to understand incentive structures and legislation that may affect large loads: Regulators can proactively coordinate with other state agencies and neighboring states to understand the current fiscal and legal environments that may affect data centers and other large loads. As of early 2025, more than 60% of states had established tax incentives to encourage data centers to build within their state.[55] Understanding these incentives and other state policy decisions can enable regulators to ask more informed questions of future load owners and utilities when reviewing load forecasts. For example, if a state has proposed or recently passed legislation that encourages or discourages development, regulators can inquire if and how utilities have integrated these changes in their forecasts of large loads.

Regulators can also encourage utilities to investigate whether prospective large loads are considering locations both in and outside of the state and reflect this "shopping around" in how individual large loads are represented in the forecast.

GOAL
Up-to-date

Increase the frequency of both updating load forecasts and updating load forecasting processes

Outdated forecasts and forecasting processes are less adept at managing uncertainty and lead to less accurate forecasting. When load forecasts display high uncertainty and have the potential to rapidly change with the addition or removal of predicted large loads, updating forecasts every one to three years in an IRP is too infrequent. Similarly, the tools and processes for forecasting large loads are rapidly evolving as new information and best practices emerge.

Options for regulators

Require more frequent reporting of long-term load forecasts: Regulators can help ensure utilities have a process for collecting and updating information about large load requests as part of forecasting that is ongoing between planning cycles. Today, especially with large loads, regulators can provide guidance for how often forecasts should be updated outside of the typical planning cycle. For example, in recognition of the unprecedented load growth, the State of North Carolina Utilities Commission requires Duke to report semiannually on economic development and the pipeline of large load projects.[56]

As processes continue to evolve, regulators can consider requiring even more frequent reporting, such as up-to-date, publicly available online dashboards that could be accessed similar to generation interconnection queues in some geographies (e.g., **Interconnection.fyi**).[57] Such dashboards would allow all interested parties to see when updates to the forecast are made and how specific projects affect the forecast, and allow third-party verification, streamlining the ability of stakeholders to comment on forecasts in dockets.

Iterate forecasting processes as new practices and end uses emerge: Load forecasting tools and processes are emerging as the industry learns more about new load drivers. Regulators can learn from other states to understand what forecasting practices leading utilities are adopting and launch investigatory proceedings that focus on forecasting best practices.

GOAL
Validated

Make load forecast data and processes visible to other stakeholders and create opportunities for accountability

Increasing the transparency of load forecasting processes and incorporating more accountability for forecasts can increase the validation of load forecasts, even when accuracy is impossible because of uncertainty. Similarly, making trends in past forecasts available can allow utilities, regulators, and other stakeholders to learn from them and can ensure utilities are iterating their approach accordingly.

Options for regulators

Encourage utilities to leverage transparent external data and forecasting tools where possible: To ensure forecast assumptions are unbiased, regulators can encourage utilities to use trusted third-party

data and tools when developing load forecasts for specific load types. Alternately, regulators can explore enabling or requiring that an independent entity, such as the state energy office or a university, produce load forecasts. For example, the California Energy Commission prepares and updates detailed forecasts of both electricity and gas consumption as well as peak demand over a 12-year timeframe.[58] Additionally, regulators can encourage utilities to update internal forecasting tools or adopt external tools (e.g., GridUp for EV load forecasting[59]) to more comprehensively and consistently forecast new end uses. At the time of publication, a national dataset that tracks large loads does not exist. Such data should be available to regulators and intervenors in any proceeding where a load forecast is implicated.

Make forecasts and actuals accessible and learn from past forecasts: Regulators and utilities can use past forecasts to improve forecasting. Requiring "backtesting" of forecasts to assess their accuracy could help utility forecasters and other stakeholders evaluate what kind of forecasting errors led to which planning decisions and identify opportunities to improve forecasting going forward. Regulators could require backtesting as a component of existing resource planning practices for vertically integrated utilities or create a docket dedicated to understanding historical load forecasting. Puget Sound Energy's 2021 IRP provides an example of backtesting: the utility included a retrospective analysis of how its five previous demand forecasts compared with reality for several key variables, identified explanations for the deviations, and integrated the lessons into the current load forecast.[60]

For large load forecasts specifically, regulators could require utilities to track and report the number of large loads that fall out of each stage of the pipeline for each type of load. With this tracking, utilities and states could develop a greater understanding of the timeline and likelihood of different types of large loads, which can then be incorporated into forecasting. If such data is published in an easily accessible format, then third parties and other regions would be able to use this data as well.

In restructured states, load forecasters within regional transmission organizations can publish each load source's contributions to individual utility forecasts, which could help address issues of double counting prospective loads among utilities. For example, PJM's Load Analysis Subcommittee publishes summary reports that include a breakdown by utility.[61]

Explore monetary incentives or penalties for forecast accuracy: Given the stakes of over- or under-forecasting, regulators could establish financial incentives or penalties for the forecasting practices or the forecasts themselves to shift risk from all customers to either large load customers or the utility itself. Requiring certain contractual agreements (e.g., tariffs, charges) can shift a portion of forecasting risk away from all customers and incentivize more accurate forecasts from large load drivers. For example, the Oregon Public Utilities Commission established two new charges that apply to customers requiring greater than 50 kilowatts: a capacity reserve charge, which is a price per kilowatt for any unused capacity outside of a 10% load forecast buffer, and an excess demand charge, which shares the risk of underestimating load requirements.[62]

To combat the natural incentive for cost-of-service utilities to over-forecast, regulators can increase utility interest in more conservative forecasting and investment strategies. One option is for regulators to require that the utility demonstrate prospective large loads have hit specific milestones of certainty before granting a Certificate of Public Convenience and Necessity. If the utility chooses to build generation before securing the predetermined level of load certainty, regulators could provide partial cost recovery for the investments made for this load.

Although not specific to load forecasting, the Business Plan Incentive in Great Britain is another example of how regulators have created an incentive for the utility to be a good steward of a specific process. In this example, the regulator instituted a Business Plan Incentive that provides a reward or penalty based on the completeness and the quality of each utility's business plan submission.[63,ii] The regulator recognized that incomplete or poor plans impeded its desired cost-effectiveness outcome and developed evaluation criteria, a process, and the incentive cap accordingly. In the United States, regulators could explore a similar mechanism to incentivize complete and quality load forecasts.

ii Business plans in Great Britian are similar to multiyear rate plans in the United States, though they are broader and include grid planning, among other things.

Making investment decisions under forecast uncertainty

Even when best practices are adopted, all forecasts remain uncertain. However, with rapid load growth upon us, utilities and commissions must be able to make decisions despite significant forecast uncertainty. Decision-making frameworks can include the following:

Prioritize "least-regrets" capital investments: Determining what constitutes a least-regret investment is a departure for regulators from more traditional least-cost decision-making. Least-regrets solutions in the face of uncertainty will be fast, affordable, and flexible. Many underrepresented options in utility portfolios meet these criteria and are focused on leveraging existing infrastructure, including energy efficiency, VPPs, grid-enhancing technologies, reconductoring, and clean repowering.[64]

In addition to solutions that are fast, affordable, and flexible, least-regrets options may also be characterized as options that are robust across a range of possible future scenarios.[65] The field of decision-making under deep uncertainty has studied such robust approaches, and water resource planners have applied them at scale.[66] Regional and interregional transmission, although higher in up-front capital costs than the other least-regrets options described here and slow to deploy, may be one such robust solution. Transmission can alleviate congestion costs and provide access to geographically distributed clean resources over the long term. US regulators can also compare individual infrastructure investments or investment levels against those of international peers, some of whom may be further along in the energy transition (e.g., Great Britain).[67]

Distribution system investments are another example of a potential least-regrets solution that provides value across many possible future scenarios. Distribution system planning is often reactive, but proactive investment can increase options for nimbly navigating load growth. Regulators can work with utilities to determine which upgrades will be relevant and prioritize those that will be useful in many load growth futures.

For example, in response to a staff proposal, the California Public Utilities Commission issued a proposed decision that sets detailed expectations for forecasting practices.[68] The decision includes using scenario planning to improve forecasting and disaggregation in distribution planning process, and implementing a pending loads category. The commission acknowledged the additional work required for both, and outlined plans for stakeholder engagement to finalize the details of how each of these would be implemented. While these proposals target distribution-level grid impacts, similar efforts could manage uncertainty at the bulk power system level.

Use tariff design or other contractual commitments to allocate risk and shore up uncertainty: Through tariffs, utilities can require up-front payments, or collateral, from large load customers to pay reservation fees for the generation and distribution infrastructure that their projected load will require. Tariffs can also have clauses that require data centers or other loads with flight risk potential to pay a fee if the load does not materialize as expected or vacates before a certain number of years. Separating the risk of serving some large loads from the rate base can protect ratepayers. Increased certainty for large load requests helps grid planners with load forecasting and transmission planning. Regulators can and should provide guidance on and oversee tariff design for large load interconnection.

The Indiana & Michigan Power Modification to Industrial Power Tariff provides an example of a structure that requires commitment to pay from large loads to reduce risk. Large load customers on this tariff must pay an exit fee if capacity is ever reduced by more than 20%, and the minimum demand charge is increased from 60% to 90%.[69] Further, companies must pay a collateral payment, recalculated annually, equal to at least 24 times their maximum expected monthly non-fuel bill, further putting the risk onto the large load customer instead of the utility.

Another example is the October 2024 AEP Ohio settlement.[70] Under this settlement, any new data center larger than 25 megawatts (MW) would have to pay at least 85% of the energy it expects to use each month. This monthly basis of pay protects against concerns of uncertain timelines as well as total load. Data centers must also pay an exit fee if projects are canceled or obligations in contracts are not met.

Even more directly, the Georgia Public Service Commission approved a rule where large loads (above 100 MW) are billed based on risk.[71] Data centers are required to pay any transmission and distribution costs that their generation requires, protecting other customers from unexpected costs.

Encouraging data centers to build new clean generation colocated with load centers can alleviate some concerns about uncertainty as well. It could incentivize them to rightsize their load projections and prevent the need to consider the data center in transmission, distribution, and capacity planning.[72]

Conclusion

This report highlights several opportunities and emerging practices for utilities and grid operators to improve the representation of large loads in their forecasts. It also features a set of load forecasting best practices that utilities and grid operators can apply today to improve forecasts regardless of the size and scale of projected load. Although large load forecasting practices are still emerging, case studies from jurisdictions projecting some of the fastest growth (Duke Energy, Dominion Energy, and Georgia Power) point toward changes needed.

Regulators also have a critical role to play in mitigating the affordability and reliability risks at stake. There are actions they can take to ensure that forecasts are more thorough, frequent, and validated. There are also complementary approaches they can take to update decision-making frameworks and navigate the remaining uncertainty, such as prioritizing least-regrets investments and adopting tariffs or other financial structures that shift risk and increase the commitment of large loads.

Additional research on large loads and their characteristics is needed to support improving forecasting. Utility planners also need standard datasets that describe load shapes, flexibility, ramp rates, and the probability of load realization for different load types. More experience is needed to inform best practices for adjusting econometric forecasts to account for large loads. New, creative approaches beyond econometric forecasting would further reduce forecast errors.

Even though all forecasts are wrong, the scale of projected load growth and its associated risks creates an imperative to ensure that forecasts remain useful in guiding consequential regulatory decisions.

Appendix: Discovery questions for load forecasting

Following are what commissions can ask a utility to ensure robust forecasting practices in the face of significant load growth.

Assumptions: Please provide a detailed description of the core components of the load forecast, including, at a minimum, projections for EVs, building electrification, population growth, VPPs, green tariffs, demand response (including time varying rates), behind-the-meter generation, and energy efficiency. Separately, please identify and justify the forecast for adoption/ownership, operation, and flexibility potential, including your assumptions about rates, controls, and other signals available to shape load. Additionally:

- For each of the core components, which methodology was used to develop the forecast?
- What were the assumptions for how core components contribute to local and aggregate peak demand? What battery backup or on-site generation assumptions were made related to large industrial loads?
- For VPPs, demand response, and energy efficiency, please provide both the energy and demand savings.
- Please describe how VPPs and demand response were modeled (e.g., as dispatchable resources or captured as reductions in the load forecast).
- Please provide documentation of your inputs with citations.

Load certainty: For industrial and data center loads, please rate the existing contracting certainty from (1) extremely prospective load to (5) extremely certain load. Explain why each load received its assigned rating. If loads were divided into specific categories (e.g., technical review, request for service), how was each category defined? Additionally:

- In a table format with each project as a row, please provide detailed updates by project, including those with delays or that were canceled. Include if contracts have been signed and if projects have broken ground.
- Please describe in detail the steps that the utility took to evaluate ramp-ups for each large load project in the forecast. Include when the utility expects contracted load to appear and reach specific levels of operation and what drives those assumptions.
- Please provide expected milestones and commitments from large load developers. If this is not the first time this kind of large load driver has appeared in the utility service territory, please include any successes or failures that the load driver has had meeting past commitments and expectations.
- For any large loads that have changed levels of certainty between the previous iteration and now, please describe which criteria led to the recategorization to a lower certainty or a greater certainty.

- Please document and share any communication the utility had with large load representatives that informs the evaluation of the large loads' likelihood to materialize.

- Please explain the customer deposit required, on a per MW basis, to attain an energy service agreement and whether the customer met previous contracting milestones.

- Please verify that energy service agreements are designed to recover all costs to the utility if a project is canceled.

Load flexibility: For industrial and data center loads, please provide information on how these loads will participate in energy efficiency and demand-response programs, including any contractual requirements or other mechanisms for ensuring participation.

- Please explain how existing or proposed energy efficiency and demand-response programs encourage large load participation. For existing programs, please include what fraction of large loads has enrolled in each energy efficiency and demand-response program, what challenges have hampered greater participation of large loads in each program, and any steps the utility intends to take to increase participation.

- For each industrial and data center load, please describe any planned backup generation. Please include details on how the customer will provide the utility with visibility into operation of the backup generation, and how the utility intends to account for the presence of the backup generation in planning.

Scenarios: Please describe in detail which scenarios the utility developed to inform this load forecast? Please include: key assumptions, how the utility determined the upper and lower bound scenarios, and how the utility will use these scenarios to inform an investment plan.

Retrospective analyses: Please provide a quantitative and qualitative analysis of how the past five load forecasts compare with actual outcomes for sales, energy consumption, and peak demand. Provide hypotheses or explanations for any deviations. Finally, please describe how the utility is addressing the source of those deviations in the current forecasts.

Bill impacts: Please describe how cost allocation of the predicted load and associated generation, transmission, and distribution investment will affect each customer class.

Clean commitments: Please document in a table which data center and industrial loads have made any public clean energy commitments. For each line, include if these entities have followed through on clean energy commitments in your territory. Please explain in detail how the utility will account for commitments to procure clean energy made by large load customers in planning.

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RMI Innovation Center
22830 Two Rivers Road
Basalt, CO 81621

www.rmi.org