The Untapped Grid:

How Better Utilization of the Power System Can Improve Energy Affordability

PREPARED BY

Ryan Hledik

Long Lam

Kate Peters

PREPARED FOR

GridLab

Utilize Coalition

MARCH 2026

Brattle

Notice

This report was prepared by The Brattle Group for GridLab and Utilize Coalition. It is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors and does not necessarily reflect individual views or positions of The Brattle Group's clients, other consultants, the reviewers listed below, or any members of the Utilize Coalition.

We would like to thank Ric O'Connell of GridLab, Ian Magruder of Utilize Coalition, and Pier LaFarge of Sparkfund for the invaluable leadership and insights they provided throughout the development of this report. We also acknowledge the valuable analytical contributions from our Brattle colleague Tina Zhang. Finally, we are grateful for review of a draft of this study by members of Utilize Coalition as well as Brattle colleagues Josh Figueroa, Peter Fox-Penner, Hannes Pfeifenberger, Akhilesh Ramakrishnan, Sanem Sergici, and Akarsh Sheilendranath.

In This Report

Section 1: **Summary**

Background

The purpose of this study is to assess an emerging opportunity to reduce electricity rates by improving the utilization of the US power system.

The affordability challenge: Several factors are driving electricity rate increases, including the growing cost of maintaining and expanding an aging transmission and distribution grid. At the same time, electricity demand is rising, driven by growth in data center development, electrification, and manufacturing.

The utilization solution: Because the power system is built to serve infrequent spikes in demand, less than half of its capacity is used throughout the year. If new electricity demand can be added to the existing power system where and when there is spare capacity, the system's fixed costs will be shared by more customers, putting downward pressure on rates.

Making it happen: The urgent need to improve system utilization is coinciding with the emergence of efficient, flexible, distributed energy technologies such as batteries, electric vehicles, smart thermostats, and other devices that reduce electricity demand at times when the power system is constrained. Encouraging their adoption offers direct financial savings to participating customers and can reduce electricity rates for all.

ANALYSIS OVERVIEW

We define a representative utility system and quantify the rate impacts of load growth with and without a focus on improved utilization.

The utility: An illustrative mid-sized (3,000 MW peak demand) utility experiencing 1,000 MW of load growth (33% increase), half of which is transmission-connected (e.g., data center) and the rest of which is distribution-connected (e.g., EVs, heat pumps).

Status quo approach: New generation, transmission, and distribution infrastructure are built to serve the new load. Costs not recovered from the new load are made up through a rate increase for all customers.

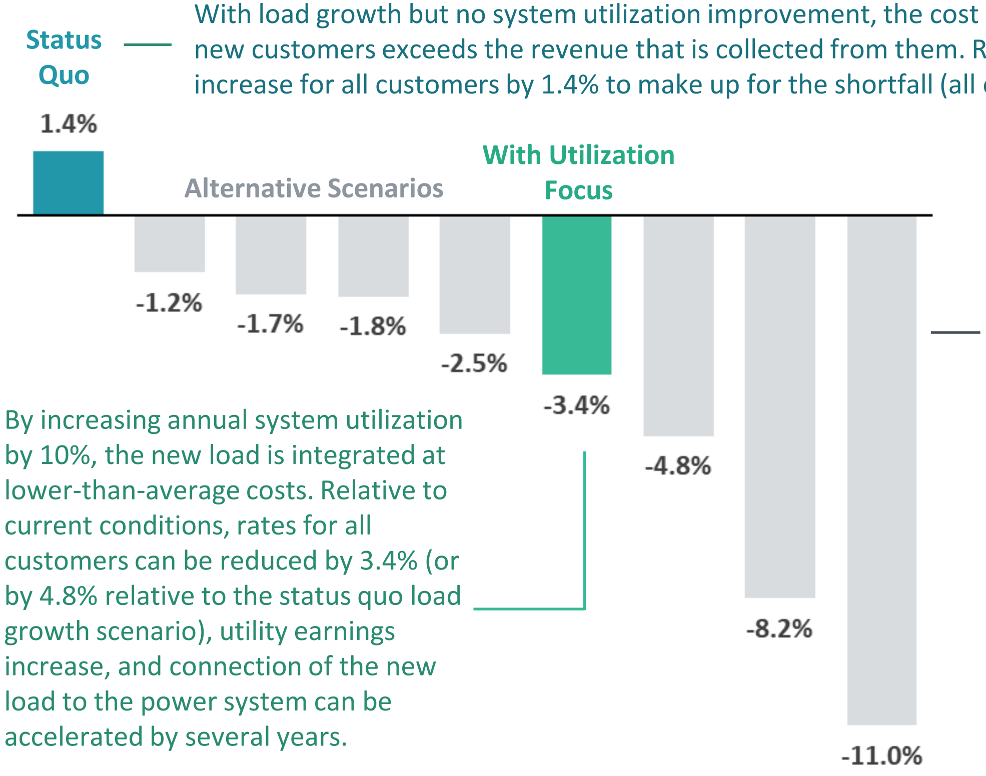
Approach with utilization focus: Peak demand reductions from the new load and from existing customers reduce the amount of supporting infrastructure that must be built. New revenue lessens the cost-recovery burden for existing customers.

The Impacts of Improved System Utilization: An Illustrative Example

In this illustrative analysis, improving system utilization can reduce customer bills and accelerate the connection of new load while still allowing utility earnings to grow relative to current levels, all else equal.

All-in Average Rate Impact Due to Load Growth

For various characterizations of the power system



Analysis of alternative scenarios shows that there is significant upside if the distributed energy resources used to improve system utilization are more impactful or available at a lower cost than assumed in the base case. More conservative assumptions still result in downward rate pressure.

Note: Impacts are shown in nominal terms.

INTERPRETING THE RESULTS

Proof-of-concept. The analysis is a plausible illustration of the benefits of improved system utilization; it is not a comprehensive analysis of all possible utility or market conditions. Tailored, jurisdiction-specific analysis is needed to understand the opportunities for any given system.

Other rate impacts. This study focuses only on the rate impacts associated with load growth and improved system utilization. It does not analyze other factors that could independently drive rate changes, such as the replacement of aging transmission and distribution (T&D) infrastructure or fluctuations in natural gas prices.

Rate design. The "status quo" analysis assumes existing rates are insufficient to fully recover incremental cost from new load. In practice, rate design can also be an effective tool for mitigating cost shifts from new loads to existing customers.

Policy implications. This paper quantifies the impact of increased system utilization but does not propose specific policies or programs in this area.

National Implications

At a national scale, improving system utilization can be a win for consumers, utilities, and new loads.

Benefits to Consumers	Analysts project that annual US electricity sales will increase by 20–30% over the next five years. Scaling this study's utility-level findings to that level of national load growth indicates that **US consumers could save $110 to $170 billion over 10 years** on their electricity bills due to system utilization improvements. Participants in programs or rates that incentivize peak demand reductions will experience **additional savings through enrollment incentives**.
Benefits to Utilities	Improving system utilization is a strategy for efficient load growth. In our analysis, a focus on improving system utilization lessens but does not eliminate the need to invest in new generation, transmission, and distribution capacity. As a result, utility earnings will still grow relative to current levels, and margins could increase with the introduction of new regulatory incentives. This focus on efficient growth will allow utilities to **focus capital deployment on the most critical infrastructure projects while also being a key enabler of economic development**.
Benefits to New Loads	Cost-effective solutions for improving system utilization allow new customers to connect to the grid **without shifting costs to other consumers**, addressing an escalating policy concern. These solutions also **mitigate the stranded asset risk of overbuilding the power system** if new load does not materialize at the level or pace forecasted, as efficiency, flexibility, and DERs can be scaled to match load growth more effectively than larger resources. Lastly, distributed resources can be brought online more quickly than other options, **accelerating speed-to-market.**

Ensuring Beneficial Outcomes

System utilization is a simple concept, but thoughtful attention to key details can help ensure the beneficial outcomes identified in this study are realized.

$$\text{System Utilization (\%)} = \frac{\text{Total energy delivered or produced on system over a given time period}}{\text{Available system capacity over the same time period}}$$

Utilization measurement should account for differences in the characteristics of generation, transmission, and distribution planning and operations.

Generation capacity should reflect expected availability of the generators during peak ("effective load carrying capability" or "unforced capacity"), as this appropriately accounts for energy-limited resources and planned outages.

Transmission capacity can be represented by the firm transfer capability of a given transmission zone; transmission utilization naturally will be lower than generation utilization due to more stringent transmission reliability planning considerations.

Distribution capacity can be calculated as the loading limits of all components at a given level of the network (e.g., feeders). Given the varied and local nature of constraints across the distribution system, an additional metric that quantifies the *share* of the system that is constrained could provide a useful complementary perspective to a systemwide average metric.

EXAMPLE PRINCIPLES TO ENSURE BENEFICIAL OUTCOMES

- **System Fundamentals:** Account for fundamental factors that drive differences in utilization across systems (e.g., customer mix, climate, distribution system configuration, generation mix).
- **Interaction with Rates:** Carefully consider the rate paid by new load when estimating the price impacts of improved utilization. Rate design and cost allocation methods will influence the extent to which rates are reduced for existing customers.
- **Cost-Effectiveness:** Improved system utilization is not a goal on its own; it is a mechanism through which to reduce electricity rates. Ensure that the methods used to improve utilization are less costly than investments in conventional infrastructure.
- **Diminishing Returns:** Take into account levels at which higher system utilization could produce diminishing benefits or even additional costs. For example, the distribution system needs times of reduced load for electrical equipment to cool, which can reduce wear and associated long-term maintenance costs.
- **Reporting:** Consider grid security considerations that may require T&D utilization to be reported at aggregate levels or subject to confidentiality agreements.

Note: See Section 5 for further details and discussion of additional principles.

Section 2: **Introduction**

New Challenges

After years of stable rates and reliable service, the US power sector needs solutions to new challenges.

Rates are increasing, creating affordability concerns.

During the years between 2015 to 2020, the average US retail electricity rate increased only by 0.4% per year in nominal terms. In following five years, the average rate has increased by 5.6% per year. In some states (e.g., California), rate increases exceeded 12% per year over the same period. The increases are broadly expected to persist or even accelerate, with tightening reserve margins, aging grid infrastructure, rising transmission and distribution equipment costs, and a need for improved resilience against extreme weather events all applying continued upward pressure on rates.

The power system is increasingly constrained.

On the bulk power system, the rapid emergence of energy-intensive data centers has led to growing concerns about system reliability. On the distribution system, the continued rise in adoption of technologies such as electric vehicles has been slowed in part by capacity bottlenecks. In both cases, this rapid demand growth is putting pressure on grid operators to make new infrastructure investments, which introduces the risk of further price increases but also an opportunity to reduce prices if more power can be sold over the existing grid.

This study explores the opportunity to reverse these trends toward reduced affordability and reliability by improving the overall utilization of the power system.

> "Over the past few years, millions of Americans have seen their electricity bills skyrocket."
>
> *Washington Post*, January 15, 2026

> "Discontent over rising power bills has become a hot political issue that is expected to spill into the 2026 midterm elections."
>
> *Wall Street Journal*, December 29, 2025

> "Concern about rising electricity rates has emerged as a leading economic and political issue. Rising electricity prices played a big role in recent elections, including statewide races in Georgia, New Jersey and Virginia."
>
> *New York Times*, December 16, 2025

The Opportunity: Improve Power System Utilization

Making better use of the existing power system can put downward pressure on rates.

The power system is built to serve peak demand. However, electricity demand is near its peak in only a very limited number of hours per year. As a result, capacity across the entire power system often remains unused.

By adding load when and where there is spare capacity, the fixed costs of the generation, transmission, and distribution systems can be recovered across a broader base of electricity sales, and everyone will pay less for their electricity consumption as a result.

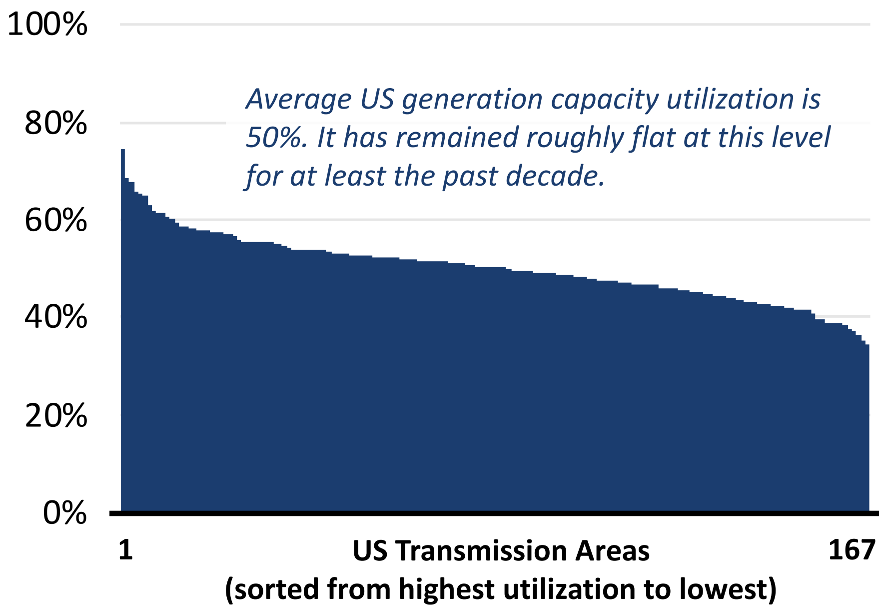
In other words, improving system utilization means the cost of the grid is shared by more customers. We carpool for the same reason—sharing resources reduces costs for everyone.

Two conditions enable improvements in system utilization: (1) load growth[1], which comes from connecting new customers to the power grid, and (2) an ability to make the load growth happen when and where there is spare capacity.

The current environment of rapidly growing electricity demand, coupled with the widespread emergence of flexible, distributed, intelligent energy technologies, has created ideal conditions for improving system utilization.

[1] In the absence of load growth, improving system utilization may enable the retirement of older, inefficient assets. However, this economic benefit is generally smaller than avoiding capital investment in new assets.

US Generation Capacity Utilization, by Transmission Area
2022–2024 Average



Note: System utilization is represented here as a region's average annual electricity demand divided by its peak demand plus an illustrative planning reserve margin of 15%. The figure shows average annual utilization factors from 2022–2024 for 167 US transmission areas, which are roughly consistent with utility or ISO zonal boundaries. Transmission area load data sourced from FERC Form 714, as compiled by Hitachi Velocity Suite.

Purpose of This Report

The purpose of this report is to provide decision-makers with an understanding of the extent to which improved system utilization can reduce electricity rates for all customers.

The remainder of the report is organized around three topics:

- A description of how improved system utilization can—and has—put downward pressure on rates, along with the tools available to achieve this outcome.
- A quantitative illustration of the rate impacts of load growth with and without improved system utilization. The analysis considers improvements in the utilization of generation, transmission, and distribution systems.
- A description of system utilization metrics, including important considerations when developing new programs or policies aimed at improving system utilization. These considerations will increase the likelihood of beneficial rate outcomes.

HOW TO USE THIS REPORT

Proof-of-Concept. The report includes an illustration of the benefits of improved system utilization, but not a comprehensive analysis of all utility conditions. It is intended to serve as the foundation for additional state- or utility-specific system utilization analysis, because each system and market has unique characteristics.

Scenario-Based Analysis. The modeled load growth, system costs, and rate impacts in this study are not a forecast of what will happen in the future, but instead reflect a plausible scenario through which the impact of system utilization on rates can be explored. Whether improved system utilization leads to lower nominal rates or otherwise slows the pace of rate growth will depend on various factors driving rate changes on the utility system.

Not a Policy Proposal. This paper quantifies the impact of increased system utilization, but does not propose specific policy mechanisms that could encourage increased utilization.

Section 3: **How It Works**

Converting Utilization Improvements into Downward Rate Pressure

Improvements in system utilization enable capital-efficient load growth, which puts downward pressure on rates.

Headroom

Create or identify spare capacity on power system

Prior studies identified 200 GW of cost-effective national potential in demand flexibility alone (roughly 20% of US peak demand). The potential is significantly higher when considering additional sources of flexibility, such as distributed storage and data center flexibility. Innovation in regulatory models may be needed to align utility incentives with this opportunity.

Load

Add load with efficient/limited investment in power system

Analysts project annual US electricity demand could increase by 25% (1,000 TWh/yr) over the next five years, driven primarily by data centers, electrification, and manufacturing. However, the forecast is uncertain. Distributed energy resources (DERs) can be scaled to match load growth more effectively than larger resources, managing the risk of overbuild and stranded assets.

Sales

Recover portion of costs of existing power system from new load

At a national average rate of 14 cents/kWh, 1,000 TWh/year of new annual electricity sales would amount to $140 billion/year in new energy revenue. A significant portion of that would pay for the existing generation, transmission, and distribution systems.

Rates

Reduce portion of existing power system paid for by existing customers

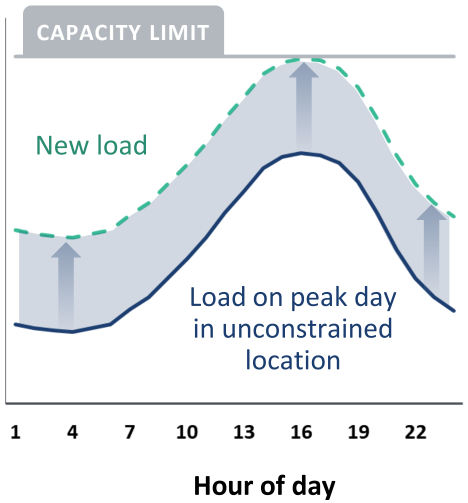
As the new load pays for a portion of the existing power system, the cost burden for other customers is reduced. As is shown later in this report, a capital-efficient approach to accommodating new load puts downward pressure on rates while still providing utilities with growth opportunities relative to current levels.

The Three Ways to Improve System Utilization

System utilization can be improved by adding new load when and where there is spare capacity. System headroom can be created through flexibility, efficiency, and other cost-effective capacity solutions.

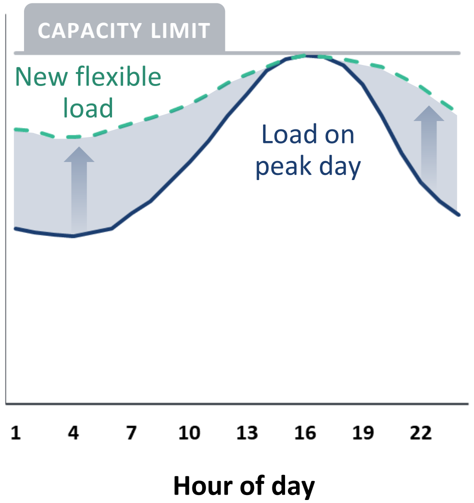
1

Add new load in **locations** where sufficient headroom already exists on the system.



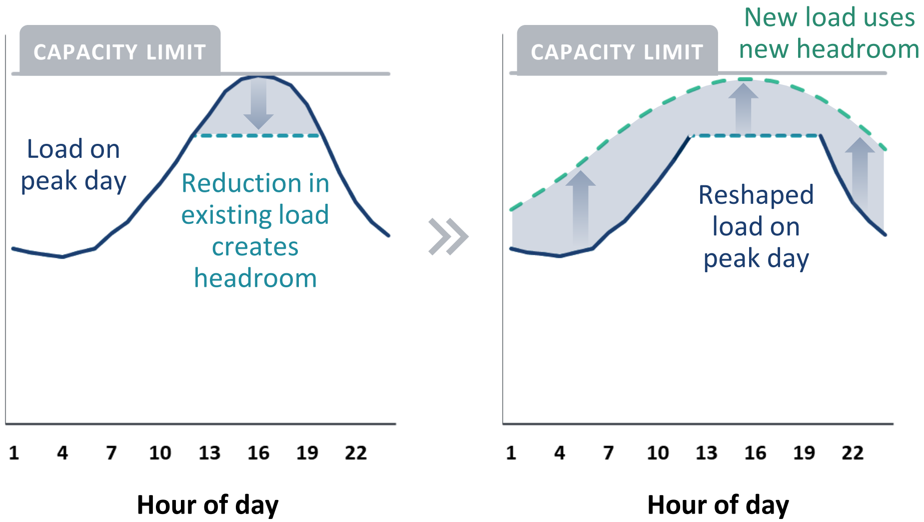
2

Add new load at **times** when there is spare capacity. This is possible if the new customers are flexible and/or can self-supply during peak conditions.



3

Incentivize technologies and behavioral changes that reduce peak demand of existing load. This creates new headroom on the system, which can then accommodate the addition of new load.



Note: These are highly simplified conceptual illustrations. The nuances of how improved system utilization would put downward pressure on rates are discussed in more detail throughout this report.

Tools for Improving System Utilization

Many options for improving system utilization are commercially available and can be deployed at scale. Both new and existing customers can contribute to utilization improvements.

Batteries

Batteries can charge from the grid at times when there is spare capacity, and discharge to the grid to create headroom during peak hours. New models are emerging to facilitate the deployment and operation of batteries across the distribution system as a grid asset. If the batteries are located on the customer's site, they can additionally provide valuable services to the customer, such as backup power and bill management.

California has developed more than 700 MW of dispatchable behind-the-meter residential battery capacity in under three years. Green Mountain Power's residential battery program is now the utility's largest peaking resource. Rocky Mountain Power has fully incorporated its battery program into the company's central unit dispatch system.

HVAC Controls

HVAC controls allow heating and cooling to be reduced during a limited number of hours per year when demand for electricity is highest. Roughly 10% of US households now have a smart thermostat, and other control technologies exist as well, including emerging options such as battery-paired heat pumps.

This concept also extends to water heating. Currently, roughly 9,700 MW of residential HVAC and water heating electricity demand can be controlled through utility demand response programs, and there is the potential to increase this capability several-fold.

EV Charging Controls

EV charging controls can shift electric vehicle charging load to hours when there is excess system capacity (e.g., overnight hours). Time-of-use (TOU) rates for home charging have reached high levels of adoption among EV owners, with some utilities exceeding 40% participation in voluntary EV TOU rates.

As EV adoption grows, actively managed charging will allow utilities to more precisely manage load. Vehicle-to-grid is an emerging capability with significant potential that would allow EV batteries to be more fully utilized to serve system demand during a select number of high-value events by exporting output to the grid.

Tools for Improving System Utilization (cont'd)

Smart Panels

Smart panels are an emerging technology to manage customer demand through circuit-level monitoring and control. They can disconnect specific circuits within a home when needed to manage the home's total demand and can potentially act as a gateway to metering and/or controlling devices within the home.

PG&E has developed a smart panel-enabled virtual power plant to shape home energy demand during up to 100 peak event hours. This premise-level control has the potential to improve downstream utilization of the distribution system at the grid's edge.

Time-varying Rates

Time-varying rates provide customers with a financial incentive to shift consumption to off-peak hours. Today, nearly 80% of residential customers are offered a time-of-use (TOU) rate by their utility. Some utilities, such as the California investor-owned utilities, Long Island Power Authority (LIPA) in New York, and Xcel Energy in Colorado have defaulted their customers to TOU rates.

TOU rates offer a static price signal that can be paired with event-based Critical Peak Pricing (CPP), which offers an additional (higher) rate on a limited number of days. These rates increase customer response and lead to greater demand reduction during stress events.

Flexible Interconnection Policies

Flexible interconnection policies are agreements between the utility and the customer to operate the customer's load within prescribed limits. These limits, sometimes referred to as "operating envelopes," are defined by the utility based on available distribution system capacity. Operating envelopes may be fixed at the time of interconnection or time-varying based on real-time available capacity ("dynamic operating envelope").

Some US utilities such as ComEd are exploring how flexible interconnections avoid or defer local distribution system upgrades that may otherwise be needed to support new load or DER connection.

Targeted Energy Efficiency

Targeted energy efficiency focuses efficiency investments on locations and end uses where they provide the greatest grid value, such as constrained feeders or peak-driven substations. Advanced analytics and hosting capacity studies increasingly enable utilities to identify locations for targeted efficiency that can create new headroom and be integrated into non-wires alternative (NWA) procurements and distribution planning processes.

Tools for Improving System Utilization (cont'd)

Grid-Enhancing Technologies

Grid-enhancing technologies (GETs) increase the usable capacity of existing transmission and distribution assets through advanced monitoring, control, and power flow optimization. Technologies such as dynamic line ratings, power flow controllers, and advanced conductors can often be deployed more quickly and at lower cost than traditional infrastructure upgrades, making them well-suited for near-term capacity needs.

Utilities across the US are piloting GETs to unlock incremental capacity and improve system utilization during peak conditions. For example, PPL realized 15% to 17% capacity increases through dynamic line ratings.

Data Center Flexibility

Data center flexibility can directly reduce the power system impact of large loads through operational adjustments or the use of on-site generation. In Texas, for example, Senate Bill 6 requires large loads with on-site generation to be available to curtail load during firm load shed events. Google has signed contracts with utilities to provide flexibility in return for accelerated interconnection.

Emerging aggregation models, such as the Bring Your Own Distributed Capacity (BYODC) model, credit data centers for supporting enrollments of residential and C&I customers in utility demand response and energy efficiency programs to offset grid impacts.

Improved System Planning

Improved system planning can surgically align investments and operations with demand growth. Proactive planning that anticipates load additions and electrification trends, supported by better load forecasting, helps utilities target upgrades to the highest-value constraints rather than overbuilding capacity. Integrated distribution planning that coordinates distribution needs with transmission and resource plans can unlock non-wires alternatives, optimize feeder and substation usage, and reduce redundant spending.

Emerging Evidence of the Benefits

Several recent analyses have found that load growth can enable downward pressure on rates.

RELEVANT STUDIES

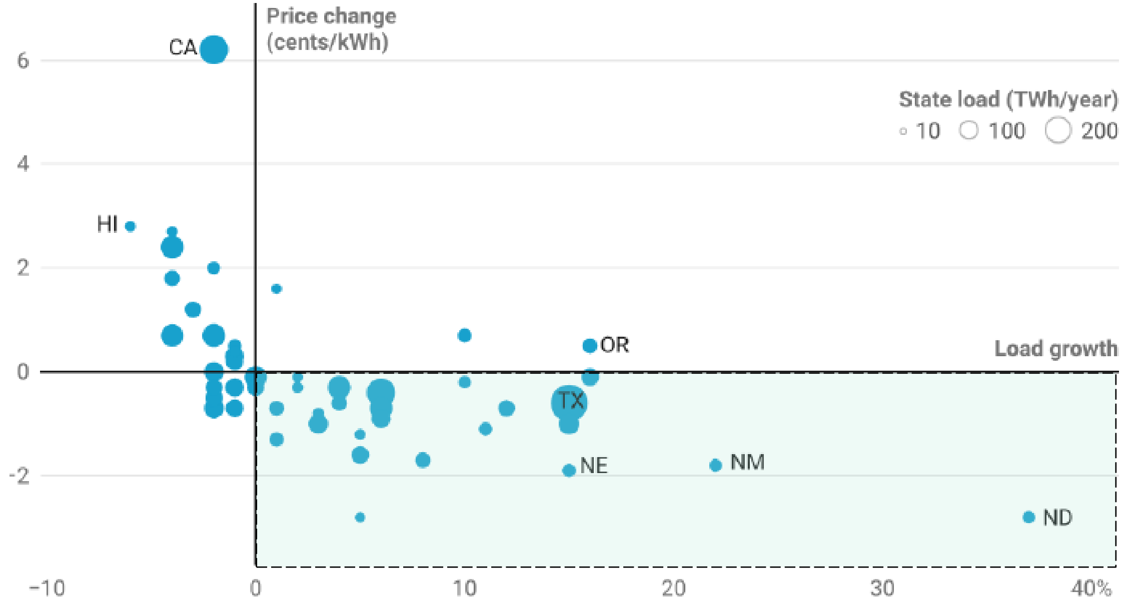
LBNL-Brattle 2025 study shows that historical load growth is associated with retail electricity price decreases.

RFF 2025 study provides empirical evidence showing that higher electricity demand reduces prices if the marginal generation cost is lower than the average cost.

Stanford 2025 study shows significant transmission headroom in the West; targeted load growth boosts grid utilization, lowers per-customer costs, and enables cost-effective system modernization.

UT Austin 2017 study attributes the 1960–1980 decline in utility network and administration costs to increasing energy consumption.

The Historical Relationship Between Load Growth and Retail Electricity Rates, by State (2019–2024)



24 states experienced load growth and declining inflation-adjusted retail electricity rates between 2019 and 2024

Source: Wiser, R. et al., "Factors Influencing Recent Trends in Retail Electricity Prices in the United States," prepared by LBNL and The Brattle Group, October 2025.

Notes: Price change is in cents/kWh, inflation adjusted to 2024$. Load growth is in percentage terms from 2019 to 2024. The source of the underlying data is EIA, created with Datawrapper.

Illustrating the Potential Rate Impact of Load Growth

The figures below provide a simplified, hypothetical illustration of how load growth could decrease or increase rates.

Hypothetical Illustration of **Rate Decrease** with Flexibility

Rate Impact of New Load:

-0.4 ¢/kWh (3% decrease in 14 ¢/kWh rate)

=

Cost of infrastructure and energy to serve new load: **$350M/yr**
\+ Ratepayer cost of creating headroom through flexibility, etc.: **$30M/yr**
– Revenue from new load: **$450M/yr**

divided by

Sales to new customers: **5 million MWh/yr**
\+ Sales to existing customers: **13 million MWh/yr**

Revenue from new load exceeds the incremental cost of serving the new load through a combination of investment in conventional infrastructure and new initiatives to create headroom (e.g., DERs, flexibility, advanced planning). Rates decrease on average as a result.

Hypothetical Illustration of **Rate Increase** without Flexibility

Rate Impact of New Load:

+0.3 ¢/kWh (2% increase in 14 ¢/kWh rate)

=

Cost of infrastructure and energy to serve new load: **$500M/yr**
\+ Ratepayer cost of creating headroom through flexibility, etc.: **$0**
– Revenue from new load: **$450M/yr**

divided by

Sales to new customers: **5 million MWh/yr**
\+ Sales to existing customers: **13 million MWh/yr**

The incremental cost of serving new load entirely from investment in conventional infrastructure exceeds the revenue generated by the new load. Rates increase for existing customers to recover the shortfall.

Note: These are simple illustrative values which differ from the more detailed analysis presented throughout this report. Utility-specific analysis should take into account ratemaking factors which could influence this outcome such as class cost allocation methods and the presence or absence of decoupling.

Section 4:

The Rate Impacts of Improved System Utilization

Section Overview

Our study provides an indicative analysis of the potential rate impacts of load growth.

Load growth could put upward or downward pressure on rates. A focus on improving system utilization increases the likelihood that load growth will contribute to beneficial rate outcomes.

In this section of the report, we estimate the impact of load growth on rates for an illustrative utility system. First, we describe the methods we use to develop this estimate. Then, we report the findings for a base case as well as seven sensitivity cases.

We conclude by extrapolating the findings to provide an indication of the bill savings that could be achieved if the scope of improving system utilization becomes a national initiative.

RATE IMPACT ANALYSIS CAVEATS

This study focuses only on the rate impacts associated with load growth and improved system utilization. It does not analyze other factors that could independently drive rate changes, such as replacement of aging T&D infrastructure or fluctuations in natural gas prices, for example.

We assume new load pays rates based on embedded costs; we do not consider the role that tariff design or other interventions can play in further mitigating adverse rate impacts for existing customers.

For simplicity, we assume all load growth occurs in the same year that capacity solutions are developed.

Approach Overview

We analyze the rate impacts of adding load to an illustrative utility system for two scenarios: one scenario focuses on improving system utilization, and the other scenario does not.

1

Define illustrative characteristics of utility system and new load

The illustrative utility has load characteristics that are broadly representative of a mid-sized U.S. investor-owned utility (e.g., 3,000 MW of peak demand and 43% generation capacity utilization).

The utility's costs also broadly align with national averages. The utility's average all-in retail rate is 14 cents/kWh. The utility's marginal capacity costs are 30% higher than its embedded (average) costs, reflecting current inflationary trends.

We assume 1,000 MW of total new load will connect to the utility's system in the near term: half will connect at the transmission level (e.g., data center), and half will connect at the distribution level (e.g., transportation electrification).

2

Calculate rate impact of adding load *without* improving system utilization (status quo)

Under the status quo scenario, we assume the new load growth will be served entirely through investment in traditional infrastructure. Specifically, 1,000 MW of additional generation and transmission capacity and 500 MW of distribution capacity will be developed to serve the new load.

The retail rate charged to the new load is strictly based on the utility's embedded costs, and therefore does not fully recover the higher incremental cost associated with the newly developed infrastructure.

Any costs that are not recovered from the new load are assumed to be collected through a uniform rate increase for all customers (new and existing).

3

Calculate rate impact of adding load *with* focus on improving system utilization

With a focus on improving system utilization, we consider a case in which the new load is accommodated on the power system with reduced investment in new infrastructure.

Half of the new transmission-level load is assumed to connect without imposing material new capacity costs on the system (e.g., through load flexibility during peak hours and/or self-supply from on-site generation).

Additionally, a 500 MW portfolio of distributed energy resources (demand flexibility, batteries, energy efficiency, EV managed charging, etc.) is developed at an average net cost of $50/kW-yr. The capacity contribution of the portfolio is derated to reflect that it offsets only a portion of the generation, transmission, and distribution infrastructure necessary to reliably serve the new load.

Note: See appendix for additional detail on modeling assumptions

The Impact of Improved System Utilization

Relative to current levels, load growth with a 10% improvement in system utilization reduces rates by 3.4%, increases utility earnings by 23%, and accelerates the connection of new load by several years.

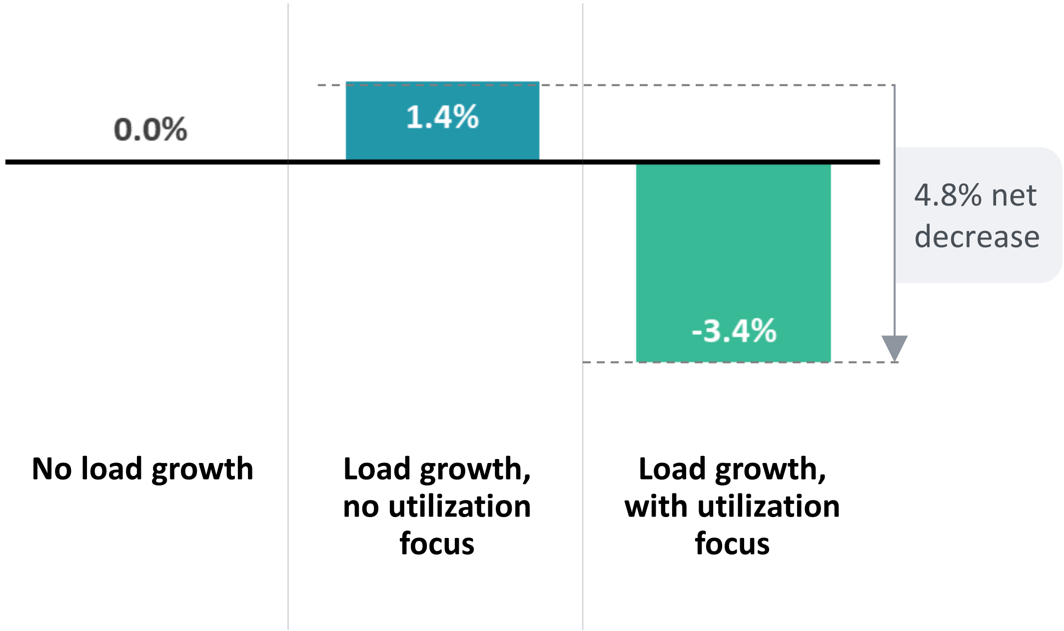
	BASELINE: No Load Growth	SCENARIO 1: Load Growth, no Utilization Focus (Status Quo)	SCENARIO 2: Load Growth, with Utilization Focus	Discussion
System Utilization	43%	44% (+1% from Base)	53% (+10% from Base)	Utilization increases slightly by building traditional infrastructure to accommodate customers with higher-than-average load factors, but meaningful utilization improvements require flexibility and efficiency, including through the deployment of distributed energy resources.
Average All-in Rate	14.0 cents/kWh	14.2 cents/kWh (+1.4%)	13.5 cents/kWh (-3.4%)	By reducing the amount of infrastructure that is needed to serve new load, flexibility and efficiency allow the cost of the grid to be shared by more customers. The result is a 3.4% rate reduction relative to a scenario without load growth, and a 4.8% rate reduction relative to a scenario in which load growth is served entirely through a capacity buildout.
Utility Earnings, Return on Equity	$317M/yr, 9.8% ROE	$435M/yr (+37%), 9.8% ROE (+0 bps)	$390M/yr (+23%), 10.1% ROE (+26 bps)	Improving system utilization lessens but does not eliminate the need to invest in new infrastructure. As a result, earnings will still grow relative to current levels, while focusing capital investment on the most critical infrastructure projects. Mechanisms that allow utility shareholders to share the benefit of net cost savings further enhance this outcome and can increase ROE.
Time to Connect New Load	N/A	5 to 10 years	1 to 5 years	The lead time to develop new utility-scale generation is over half a decade due to supply chain bottlenecks and interconnection delays. Flexibility, distributed energy resources, and other options for improving system utilization do not face the same barriers to scaling quickly.

Notes: Totals may not exactly sum due to rounding. System utilization is represented here as average hourly energy sales divided by installed generating capacity. See next section for further discussion of ways to measure utilization at each level of the system (generation, transmission, and distribution). The utility earnings estimate assumes a vertically integrated utility and a regulatory mechanism through which cost savings are shared between customers and shareholders. 10 basis points (bps) represent 0.1% of return on equity (ROE). See appendix for further detail. Rate impacts are shown in nominal terms.

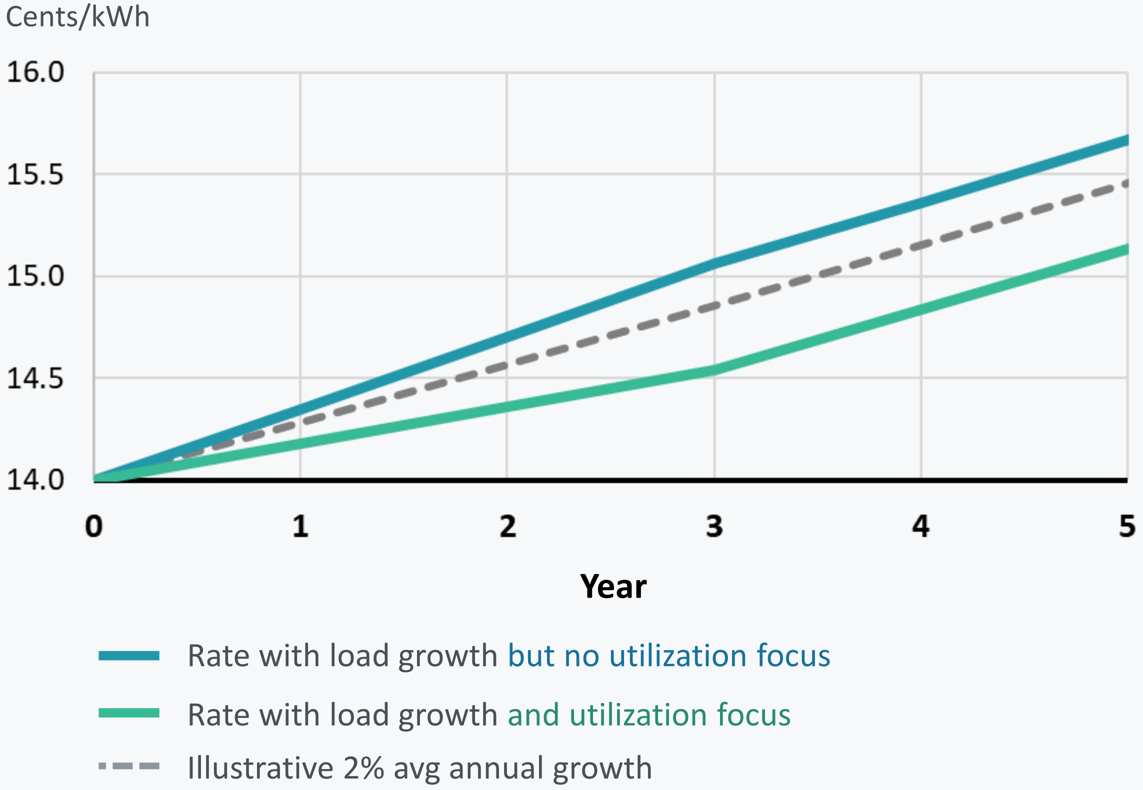
Annual Rate Impacts

Many factors may drive rates up in the future. Improving system utilization makes power cheaper and can dampen rate increases that may result from other inflationary price pressures.

Total Rate Impact of Load Growth
With and without focus on system utilization



5-year Trajectory of Average All-in Rate
Assuming illustrative 2%/year nominal baseline growth



Note: Figure based on illustrative assumption that rate impacts of load growth phasing in over three-year period. With less baseline rate inflation, improved system utilization could produce nominal decreases in rates. Values are shown in nominal terms.

Alternative Scenarios

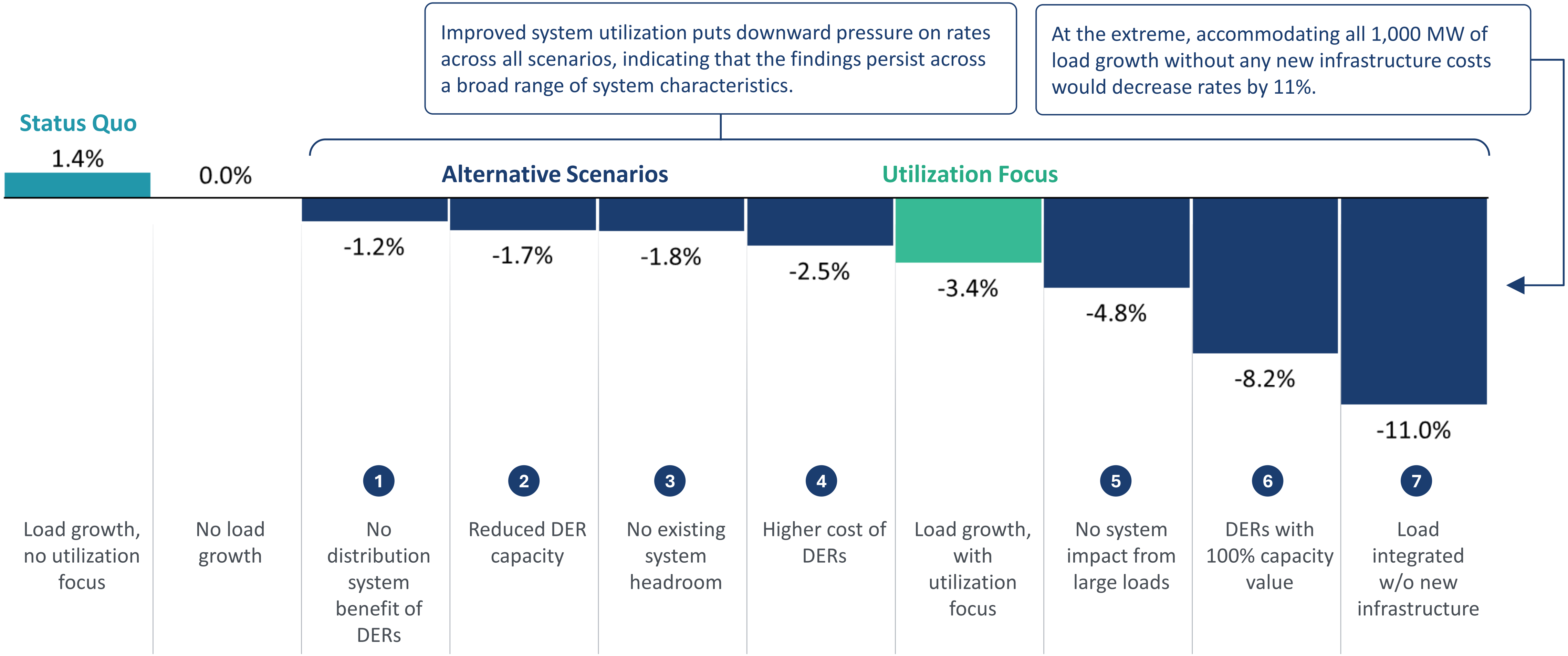
We analyze seven alternative scenarios to test the strength of the findings.

Alternative Scenarios	Base Assumption	Alternative Scenario Assumption	Impact of Alternative Assumption on Rate, Relative to Base
1. No distribution system benefit of DERs	DERs have 40% distribution capacity credit (i.e., 1 MW of DER capacity creates 0.4 MW of distribution system headroom)	DERs are used exclusively to provide bulk system capacity and do not create headroom on the distribution system	↑
2. Reduced DER capacity	DER portfolio has 500 MW of capacity	DER portfolio has 250 MW of capacity	↑
3. No existing system headroom	50 MW of bulk system headroom and 100 MW of distribution system headroom, beyond standard reliability reserve margin	No existing system headroom to accommodate new load growth	↑
4. Higher cost of DERs	DERs provide capacity at average cost of \$50/kW-year (cost of nameplate capacity, before availability derate)	DERs provide capacity at an average cost of \$100/kW-yr	↑
5. No system impact from large loads	Half of 500 MW of new transmission-connected load served without new infrastructure (e.g., through self-supply)	None of 500 MW of new transmission-connected load requires new infrastructure (e.g., due to bring-your-own-capacity mandate)	↓
6. DERs with 100% capacity value	Capacity value of DERs is 90% for generation, 25% for transmission, and 40% for distribution	Capacity value of DERs is 100% for generation, transmission, and distribution (i.e., highly flexible and optimally-sited portfolio)	↓
7. Load integrated w/o new infrastructure	Infrastructure investment, flexibility, or DERs are needed to accommodate load growth	Extreme case in which all load growth is accommodated without new infrastructure costs	↓

Scenario Analysis Results

The downward rate impact of improved system utilization is robust across a range of system conditions.

Rate Impact of Load Growth Across Scenarios



National Implications

At a national scale, consumers could save hundreds of billions of dollars over the next decade due to system utilization improvements.

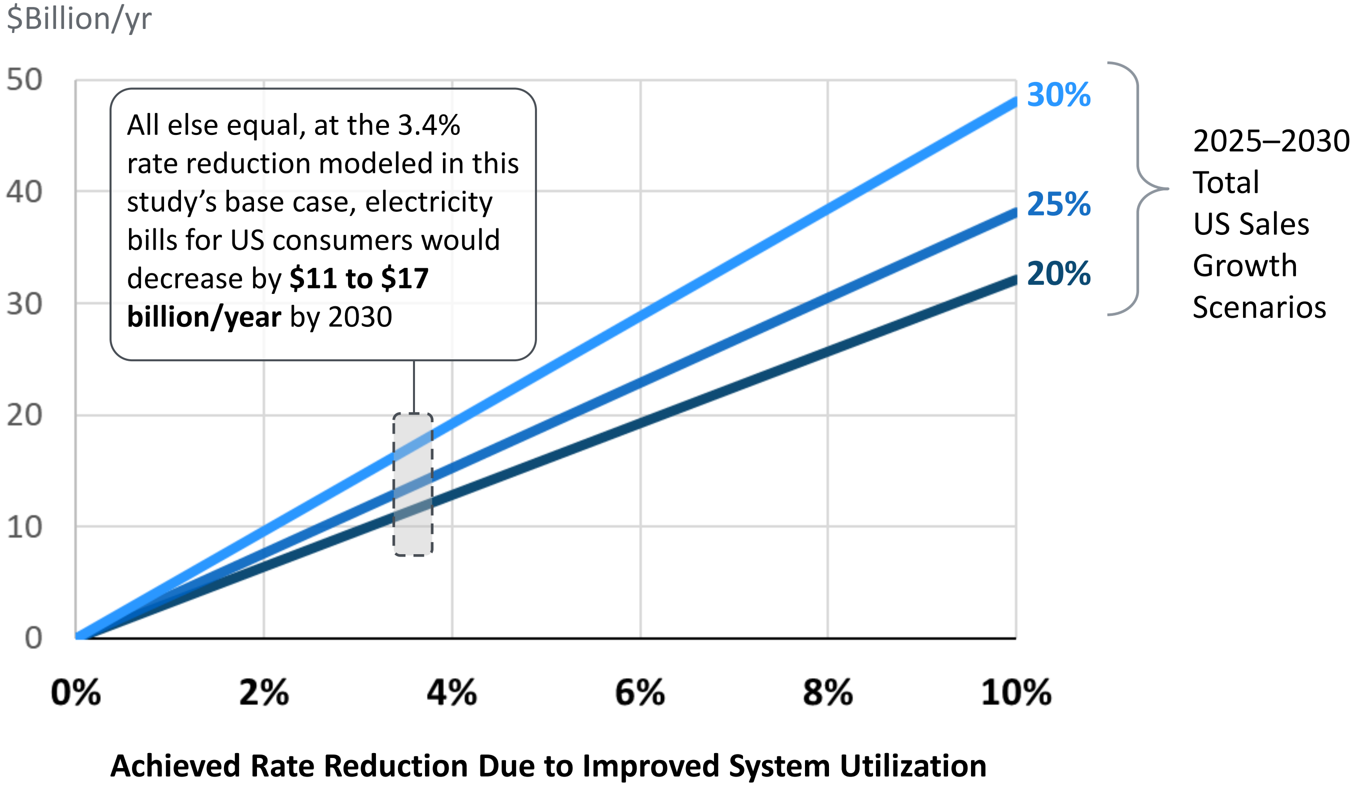
Extrapolating the findings of our illustrative utility analysis to the national level provides an indication of the total reduction in electricity bills that could be experienced by existing consumers due to improvements in system utilization.

Between 2025 and 2030, analysts forecast that annual electricity sales in the US could increase by between 20% and 30%. Scaling the results of our base-case analysis to that level of load growth suggests annual consumer electricity bill savings of $11 billion to $17 billion per year by 2030, all else equal. Over a 10-year period, the savings would amount to $110 billion to $170 billion.

If downward pressure on rates exceeds the finding in our base case (as shown in some alternative scenarios), the bill savings could be significantly higher, approaching $500 billion over 10 years if a 10% rate reduction is achieved.

Reduction in National Annual Electricity Bill Due to Improved System Utilization

For Range of Achieved Rate Reductions and Electricity Sales Growth, by 2030



Note: Values are shown in nominal terms.

Applicability of Findings in Organized Wholesale Markets

System utilization improvements can be beneficial in both vertically integrated and restructured states.

Vertically Integrated Utilities

Vertically integrated utilities own generation, transmission, and distribution. Examples are Southern Company and Duke Energy. In some cases, vertically integrated utilities may also participate in wholesale markets (e.g., Dominion in PJM, utilities in MISO).

Improvements in system utilization impact the rates of vertically integrated utilities as described throughout this report. The utility sets rates to recover its embedded (historical average) costs. If new customers can be served at a lower cost, rates can be reduced for all customers across the generation, transmission, and distribution systems, and the utility earns its revenue requirement.

A benefit of the vertically integrated utility structure in this context is that the utilities have more flexibility in how they recover costs from customers (e.g., by directly assigning costs to new customers and by being insulated from price volatility of wholesale capacity markets).

Distribution Utilities in Restructured States

Distribution utilities own only the distribution system, but still often provide supply (energy) to customers by procuring it through bilateral contracts or purchases from the wholesale energy and capacity markets (e.g., most utilities in PJM, New York, and New England).

Distribution utilities can use system utilization improvements to directly reduce distribution rates, which can account for a third or more of a residential customer’s bill. By being located at the edge of the grid, DERs are well suited to provide this benefit.

Additionally, when distribution utilities are the customer’s energy providers, they pay for generation and transmission capacity based on their contribution to the broader system’s peak demand. Reducing forecasted peak demand is an opportunity to further mitigate rate increases, though when the pace of load growth significantly exceeds supply (e.g., in PJM), capacity prices may remain elevated.

Section 5:

Principles for Measuring System Utilization

Section Overview

An essential first step in improving system utilization is to appropriately measure it.

The concept of improving system utilization is fundamentally simple: increase the use of existing power system assets. However, appropriately measuring system utilization—and developing new programs and policies that aim to improve it—are complex issues.

In this section, we first discuss methods for measuring system utilization, including important differences between generation and network utilization, and data sources.

We then provide an overview of several important issues that decision-makers will need to consider to increase the likelihood that new initiatives targeting system utilization will provide beneficial rate outcomes for all customers.

Background

Fundamentally, utilization is a comparison of energy to system capacity over a given period of time.

$$\text{System Utilization (\%)} = \frac{\text{Total } \textbf{energy} \text{ delivered or produced on system over a given time period}}{\text{Available system } \textbf{capacity} \text{ over the same time period}}$$

Generation utilization example:

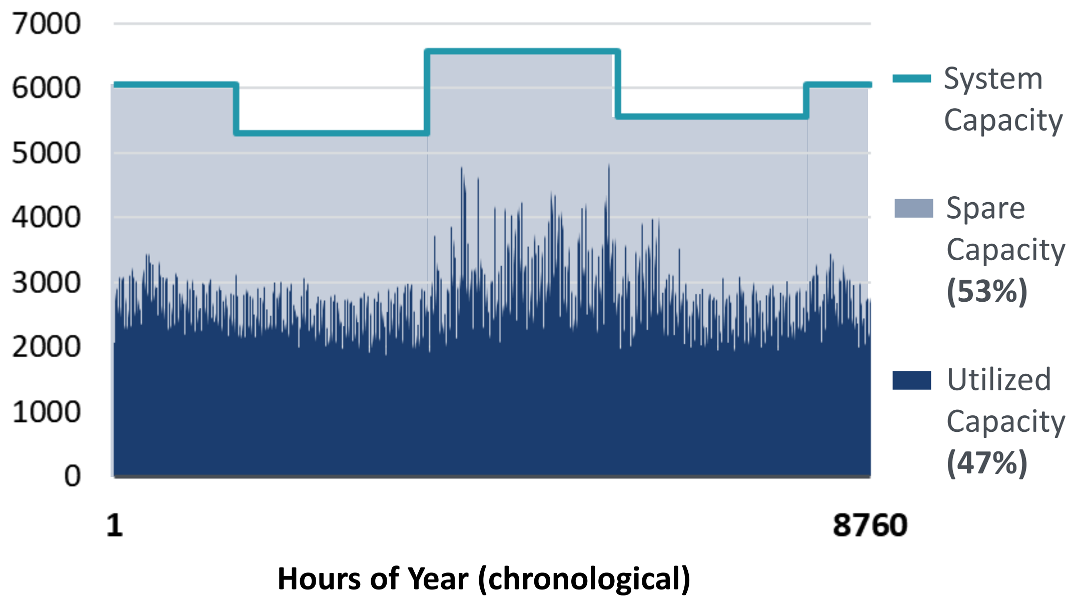
A utility has 6,500 MW of generating capacity during the four summer months, and between 5,000 and 6,000 MW of generating capacity during the other eight months. The utility's average capacity over the year is 6,000 MW. The utility's fleet of generators produces 24.7 million MWh of energy over the year.

The utilization of the utility's generation fleet is:

$$\mathbf{47\%} = \frac{\text{24.7 million MWh}}{\text{6,000 MW capacity} \times \text{8,760 hours per year}}$$

Illustrative Hourly Output from Generation Fleet Over a Year

MW



Notes: System capacity differs by season based on variation in resource availability such as renewable generation and thermal planned and maintenance outages. We show illustrative seasonal derates driven by thermal planned outages in a system primarily reliant on thermal rated capacity.

Measuring System Utilization: Generation, Transmission, and Distribution

	Generation	Transmission	Distribution
Example Opportunity	Alleviate load growth-related resource adequacy challenges during peak hours by reducing system peak demand through demand response, time-varying rates, and peak-targeted energy efficiency.	Use grid-enhancing technologies such as dynamic line ratings to increase utilization of existing transmission capacity, or use distributed batteries to relieve peak congestion on a constrained transmission corridor.	Use flexible interconnection policies to accommodate the addition of new electric vehicle load or leverage smart panels or flexible heat pumps to add load without exceeding loading limits on the secondary distribution system.
Example Utilization Metric	For the entire generation fleet, calculate annual generator output divided by total installed “unforced capacity.” At the fleet level, this appropriately accounts for energy-limited resources and planned outages due to maintenance. Capacity can vary over the applicable time period to reflect changes in availability.	For a given transmission zone, calculate annual total transmission flows and divide by the zone’s firm transfer capacity. Using firm transfer capacity as the denominator reflects the reliably available capability reserved for firm service, while still allowing non-firm transfers to use remaining headroom and increase measured utilization.	Across all feeders in a distribution system, calculate a load-weighted average of each feeder’s utilization, where feeder utilization is defined as metered load on the feeder divided by the feeder’s loading limit. Using customer meter-level load implicitly accounts for line losses on the feeder, reductions in which could show up as higher measured utilization.
Key Considerations	Note that total output of the generation fleet may differ from the utility’s load due to imports/exports and renewables curtailments. Measuring utilization over a multi-year period helps to normalize for weather-related variation in demand. Planning reserve margins will necessarily limit achievable utilization.	Transmission utilization will naturally be lower than generation utilization; transmission planning for N-1 contingencies (i.e., the loss of any single component) generally results in a higher level of capacity redundancy than at the generation level.	As a secondary metric, an assessment of the portion of the distribution system facing capacity constraints (e.g., number of feeders) will provide additional perspective on utilization improvement opportunities relative to the systemwide average described above.

Note: In the above examples, the measure of capacity (i.e., the denominator) would be multiplied by 8,760 hours of the year to produce a utilization metric between 0% and 100%.

Ensuring Beneficial Outcomes

As decision-makers develop policies or programs aimed at improving system utilization, the following considerations will increase the likelihood that the outcome reduces rates for all customers.

System Fundamentals. Certain fundamental factors outside a utility's control will influence the system's utilization level. For example, large industrial customers tend to have higher load factors than residential customers; a utility with a larger industrial base may naturally have higher system utilization as a result. Policies encouraging improvements in system utilization should take these utility-specific conditions into account. In other words, the focus of new utilization initiatives should be on incremental improvement from existing levels, rather than attainment of a single utilization value that is considered to be "universal" across all utility territories.

Interaction with Rates. The rate paid by new load will influence the extent to which improved utilization reduces rates for existing customers. Higher rates for new loads, relative to the cost of serving that new load, will improve the outcome for other customers. Relatedly, cost allocation is an important consideration in the ratemaking process; new methods may need to be developed to ensure the benefits of improved system utilization are realized by all customers and not restricted to specific customer classes.

Cost-Effectiveness. Improved system utilization is not an end in itself; it is valuable to the extent that it helps lower total system costs and, ultimately, customer rates. Regulators, therefore, need to ensure that strategies used to raise utilization—such as deploying DERs—are more cost-effective than conventional grid investments that would otherwise be required. In other words, initiatives aimed at improving operational efficiency should be evaluated not only on whether they increase utilization, but also on whether they deliver net cost savings and improve overall cost efficiency.

Diminishing Returns. There are levels at which higher system utilization could produce diminishing benefits or even additional costs. For example, the distribution system benefits from times of reduced load for electrical equipment to cool. Further, some excess system capacity is needed to allow equipment to be taken offline for maintenance or to prepare for extreme weather conditions. Goals for improving system utilization should take these limits into account.

Reporting. Aggregate generator data is typically available from utility resource plans, ISO/RTO annual capacity reports, or public sources such as the US EIA's Form 860 and Form 923. However, grid security considerations may prevent detailed transmission and distribution data from being reported publicly. It may be necessary for system operators to report utilization metrics at aggregated levels, potentially subject to confidential review by regulatory commissions. Utilities increasingly are publishing hosting capacity data with this information for the distribution system.

Ensuring Beneficial Outcomes (cont'd)

Timescale. System utilization can be measured over different periods of time (e.g., seasonal versus annual). Annual measurement generally is an effective time period to use, because it captures seasonal differences in utilization. Measuring over several years is a transparent alternative to weather normalization.

Applicable System. Utilization should be measured separately for generation assets, the transmission system, and the distribution system. Decision-makers will need to decide whether to focus on all or a subset of these, depending on cost drivers and market structure.

Geographic Granularity. Measuring utilization for the system as a whole is important to account for utilization improvements that result from connecting new load in locations with existing headroom. As a secondary consideration, utilization could be measured for specific constrained zones/locations in order to identify location-specific opportunities or locations that have already reached high levels of utilization. Data availability will influence the level of geographic granularity that is possible.

Business Model Innovation. Maximizing opportunities to improve system utilization may require regulatory or business model innovation, because traditional utility incentives are tied to capital investment, not to getting more value from existing assets. Updating performance incentives, cost-recovery rules, and planning requirements can reward utilities for least-cost outcomes, enable third-party participation where efficient, and ensure benefits are shared with customers through lower long-run costs and rates.

Weather Effects. Year-to-year fluctuations in weather will drive changes in load patterns and, therefore, cause variability in measurements of system utilization. System utilization could be measured on a weather-normalized basis to address this variation, though weather normalization techniques are not always transparent. Reporting system utilization as an average over several recent years of weather conditions could be a pragmatic alternative.

Interaction with Decarbonization Goals. Improving utilization of the generation system means increasing production from the existing fleet of generators. Policymakers should be aware of and weigh the trade-offs of improved affordability relative to decarbonization goals, if higher utilization contributes to increased output from carbon-emitting resources. Conversely, system utilization improvements can enable achievement of decarbonization goals if the distributed resources deployed to facilitate the improvements are sources of clean energy (e.g., solar-plus-storage or energy efficiency measures). Improved system utilization can also accelerate the adoption of electrification measures by relieving distribution system bottlenecks.

Improving grid utilization is a meaningful opportunity to enhance affordability and reliability. Achieving these benefits will require thoughtful, system-specific goals that account for reliability needs, applicable regulatory structures, policy requirements, and local conditions. This balanced approach will ensure that the utilization improvements complement strategic infrastructure investment, directing capital where it delivers the greatest long-term value.

Section 6: **Conclusion**

Moving Forward

This study is the beginning, not the end, of the discussion on the benefits of improved system utilization.

Our study has highlighted the potential for load growth to be an energy affordability solution, rather than a problem. Specifically, the study has shown that improvements in system utilization through load growth can put downward pressure on rates for consumers, while accelerating the connection of new load and reducing financial risk. Work remains to ensure initiatives in this area achieve the desired energy affordability outcomes. We recommend the following next steps.

1

Data Collection

Measuring system utilization requires assembling the right data. Generation utilization metrics are often available from public sources, but transmission and distribution capacity ratings and limits are frequently confidential. To fill these gaps, regulators and analysts should work with utilities and system operators to establish clear data definitions, confidentiality protections, and data-sharing processes.

2

System Characterization

Setting utilization targets requires an accurate characterization of the system in question. Utilities differ in key drivers of utilization—such as customer mix, climate, infrastructure age and condition, and network topology. Regulators and utilities should document these factors up front and design utilization initiatives and benchmarks that reflect local constraints and operating realities, rather than applying one-size-fits-all targets.

3

Potential Assessment

Improving system utilization requires identifying the options that are feasible and cost-effective for a specific utility. The best opportunities will vary; some systems may benefit most from targeted energy efficiency, while others may find greater value in distributed batteries or load flexibility, for example. Developing a “supply curve” of utilization-improvement options, ranked by cost and potential impact, helps regulators and utilities design informed, least-cost initiatives.

4

Implementation Plan

Market, regulatory, and technical barriers can limit how effectively utilization tools deliver value. Alongside evaluating cost-effectiveness, utilities, regulators, and service providers should assess near-term feasibility by identifying the specific barriers that constrain deployment or operations. Where benefits justify it, they should pursue targeted reforms, such as rule changes or interconnection/process improvements, to remove barriers and unlock longer-term, system-wide optimization.

Technical Appendix

Modeling Assumptions: Illustrative Utility

	Base Assumption	Support for Assumption
Peak Demand	3,000 MW	Representative of mid-sized investor-owned utility (e.g., AES Indiana's system peak is 2,750 MW; Idaho Power's peak is about 3,900 MW)
Annual Load Factor (Avg demand / peak demand)	50%	Representative of many utilities (e.g., Georgia Power, Puget Sound Energy)
Planning Reserve Margin	15%	Generally consistent with standard utility planning practices. Represents capacity target above peak demand, to ensure reliability during abnormal load conditions.
Existing System Headroom	50 MW at transmission level 100 MW at distribution level	Illustrative assumption. Represents utility system that is modestly overbuilt relative to its target planning level.
All-in Average Rate	14 cents/kWh	Representative of typical average retail rate for US utility (e.g., ComEd, Arizona Public Service). Represents an average across all customer classes.
Embedded Costs	Share of total revenue requirement: Energy = 25%, generation capacity = 15%, transmission = 15%, distribution = 40%, other = 5%	Illustrative assumption that broadly aligns with cost breakdown reported by EIA.
Marginal Costs	Capacity costs are 30% higher than embedded costs.	Illustrative assumption to reflect current inflationary environment.
Financial Metrics	ROE = 9.8%, WACC = 7.1%, equity ratio = 50%	Broadly representative of U.S. investor-owned utilities.

Modeling Assumptions: Case Without Focus on Utilization

	Base Assumption	Support for Assumption
Peak Demand of New Load	500 MW transmission-connected 500 MW distribution-connected	500 MW is larger than most existing data centers, but smaller than announced AI training facilities, which can reach 1 GW. 500 MW of distribution-connected load could represent natural load growth as well as impact of transportation and building electrification.
Annual Load Factor of New Load	70% for transmission-level load 40% for distribution-level load	70% represents the relatively high load factor of large customers such as data centers. 40% is representative of the load factor of a fleet of light-duty electric vehicles.
Retail Rate Paid by New Load	Based on embedded costs. Energy charged on volumetric basis, capacity charged on peak demand basis. Transmission-connected load is not charged for distribution. Any costs that are not recovered from the new load are assumed to be collected through a uniform rate increase for all customers (new and existing).	Illustrative assumption.
Flexibility Assumptions	New load is inflexible. All new load beyond the modest amount of existing system headroom is served with development of new generation, transmission, and distribution capacity.	Illustrative assumption.

Modeling Assumptions: Case with Focus on Utilization

	Base Assumption	Support for Assumption
Characteristics of New Load	Same as case without focus on utilization (see prior page)	N/A
Flexibility of Transmission-Connected Load	250 MW out of 500 MW can be served without new infrastructure investment	Representative of a portion of the new load being flexible during peak hours or being served through on-site generation.
Distribution-Connected Flexibility	500 MW of DERs (e.g., generation, storage, flexibility, efficiency) deployed at distribution level	Represents 12.5% of the utility's system peak demand. Many DSM potential studies have shown that this level of deployment is achievable, and some US utilities already have built peak reduction portfolios of this scale.
Cost of Distribution-Connected Flexibility	$50/kW-yr	The net cost of achieving peak demand reductions through demand-side initiatives varies by measure. $50/kW-yr is reflective of costs to the utility that could incorporate buy-downs from hyperscalers, or partial customer funding of devices that provide both grid and private value, for example. As a result, the utility pays only a fraction of total technology costs.
Capacity Impact of Flexible Resources	Capacity credit: 90% for generation capacity, 25% for transmission capacity, 40% for distribution capacity.	High generation-level capacity credit is consistent with recent PJM ELCC values for demand response. Lower transmission-level capacity credit reflects that the majority of transmission system investment is not driven by peak demand growth or otherwise avoidable with distributed resources. Moderate distribution capacity value assumes DERs are operated to "stack" distribution and bulk system value, with some geographically-targeted deployment to constrained locations of the grid.
Energy Impact of DERs	44,000 MWh/yr of energy savings (equivalent to year-round savings at 1% of 500 MW peak impact)	Accounts for the possibility that a portion of the DERs will reduce peak by reducing overall energy consumption. This effect is accounted for when quantifying the rate impact, because it offsets some of the downward pressure otherwise achieved through load growth.
Shared Savings Model	10% of net avoided cost attributable to distributed flexibility and efficiency is returned to utility shareholders.	A utility shared savings model allows utilities to retain a portion of cost savings achieved through activities that improve utilization and reduce costs, aligning shareholder incentives with least-cost solutions while still delivering the majority of benefits to customers.

Additional Reading on System Utilization Opportunities

Alliance to Save Energy and The Ad Hoc Group. (2026). *Bridging the Load Gap: A Collaborative Path for Utilities, Hyperscalers and Customers*.

Cohen, J. et al. (2025). *How Virtual Power Plants Can Help the United States Win the AI Race*. RMI.

Dong, Z. et al. (2025). *How Do Residential Greenhouse Gas Mitigation Technologies Affect Electricity Prices and Consumer Welfare?* (Working Paper 25-28). Resources for the Future.

Ducey, D. & Granholm, J., *Data Centers Can Drive Affordability*. Op-Ed in *Newsweek*. January 6, 2026.

EPRI (2026), *Win-Win Watts: When Can Data Centers, Efficient Electrification, and New Loads Lower Electricity Prices?* Accessed January 27, 2026

Fares, R. & King, C. (2017). *Trends in Transmission, Distribution, and Administration Costs for U.S. Investor-Owned Electric Utilities*. *Energy Policy*, 105, 354-362

Fox-Penner, P. et al. (2025). *Affordability, Rates, and Clean Capital Efficiency: A Path for the Power Industry's Turbulent Next Decade*. The Brattle Group.

GridCARE (2025), *AI Data Centers as Engines of Affordability and Capital Investment*.

Hledik, R. & Peters, K. (2023). *Real Reliability: The Value of Virtual Power*. Prepared for Google. The Brattle Group.

Norris, T. H. et al. (2025). *Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems*. Nicholas Institute for Energy, Environment & Sustainability, Duke University.

Osaka, S. (2025). The U.S. May Have a Secret Weapon Against Rising Electricity Prices. *The Washington Post*.

Pfeifenberger, J. et al. (2025). *Optimizing Grid Infrastructure and Proactive Planning to Support Load Growth and Public Policy Goals*. Prepared for Clean Air Task Force. The Brattle Group.

Prabha, R., & Min, L. (2025). *U.S. Transmission System Utilization Study Phase 1: WECC*. Stanford University.

Wiser, R. et al. (2025). *Factors Influencing Recent Trends in Retail Electricity Prices in the United States*. *The Electricity Journal*, 38(4), 107516.

About the Authors

Ryan Hledik

PRINCIPAL | SAN FRANCISCO

Ryan.Hledik@brattle.com

Ryan focuses his consulting practice on regulatory, planning, and strategy matters related to emerging energy technologies and policies. His work on the grid edge has been cited in federal and state regulatory decisions, as well as by *CNN*, *Forbes*, *National Geographic*, *The New York Times*, *NPR*, *PBS*, and *The Washington Post*. He has published more than 30 articles on electricity matters, presented at industry events in 11 countries, given lectures on distributed grid economics at Penn, Stanford, and Yale, and served on the advisory boards of a demand flexibility startup and an energy storage trade association. He is a founding Alumni Policy Advisor for the Kleinman Center for Energy Policy at the University of Pennsylvania. Ryan received his MS in Management Science and Engineering from Stanford University and his BS in Applied Science from the University of Pennsylvania.

Long Lam

MANAGING ENERGY ASSOCIATE | WASHINGTON, DC

Long.Lam@brattle.com

Long is an expert in the development and implementation of decarbonization strategies and in the design and analysis of clean energy policy. His work for large companies and governments with net-zero commitments and for regulated utilities, market operators, and regulators focuses on several areas, including emissions reduction strategies and implementation program development for entities pursuing large-scale decarbonization, granular accounting of Scope 2 emissions and clean energy procurement, and the design and evaluation of smart rates, distributed energy resources, and load flexibility programs.

Kate Peters

ENERGY ASSOCIATE | NEW YORK

Kate.Peters@brattle.com

Kate focuses her research on resource planning in decarbonized electric markets and economic analysis of distributed energy resources. She has supported utilities, renewable developers, research organizations, technology companies, and other private-sector clients in a variety of energy regulatory and strategy engagements. Kate received her BA in Environmental Economics from Middlebury College.