Beyond the Headlines:

An Empirical Analysis of Data Center Grid Utilization, Cost-of-Service and Revenue Contributions

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Prepared by:

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Authors & Acknowledgments

Project Team

Energy and Environmental Economics, Inc. (E3) is a leading economic consultancy focused on the power and broader energy sector in North America. For over 30 years, E3's data driven analysis and unbiased recommendations have been utilized across the power industry by the utilities, regulators, government agencies, project developers, investors, and non-profit entities. E3 has offices in San Francisco, Boston, New York, Chicago, Denver, and Calgary.

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Glossary of Terms

Term	Definition
Collateral	Property or asset that has a specific value which can be pledged by utilities and large consumers to mitigate the risk of non-payment.
Congestion	A condition where the amount of electricity flowing through grid infrastructure exceeds its physical capacity, constraining the flow of electricity through the grid and leading to reliability risks and potential cost increases.
Cost of Debt	Net effective interest rate that regulated utilities pay on debt used to finance investment costs.
Decarbonization	The process of reducing greenhouse gas (GHG) emissions.
Demand Charge	A component of an electric utility bill that is based on the highest rate of power (kW) that a customer consumes during a specific period.
Distribution	The lower-voltage network and related equipment that delivers electricity from transmission-connected substations to end users (homes, businesses, and many industrial facilities).
Fixed Costs	Expenses to build, operate, and maintain the electric infrastructure necessary to reliability provide power, which do not change based on the actual amount of electricity consumed by customers.
Generation	The process of producing electrical energy from primary energy sources (e.g., natural gas, coal, nuclear, hydro, wind, solar) at power plants or other generating facilities. Generation output is typically stepped up in voltage and delivered to the transmission system.
Generation Capacity	The maximum amount of electrical power, measured in megawatts (MW), that can be generated by a resource or power plant when operating under specific conditions.
Headroom	The unused, available capacity of electric infrastructure to support increased demand.
Interconnection	The process by which a generating resource, storage facility, or large load is physically and contractually connected to the electric grid.
Interregional Transmission	High-voltage transmission facilities that connect two or more neighboring grid regions, enabling the transfer of electricity across regional boundaries.
Load Departure	A reduction in a utility's expected electricity demand when a customer reduces consumption from that utility.
Load Factor	A measure of how consistently electricity is used over time, calculated as average load divided by peak load over a given period.
Peak Load	The maximum amount of electricity demand over a specified period.
Rate Base	Total approved valuation of a utility's net assets.
Rate of Return	Percentage of profit that a utility is authorized to recover on its invested capital
Reliability	The ability of the electric system to consistently deliver power to customers in the quantity and quality required, even in the face of equipment failures, extreme weather, or other unexpected events
Resilience	The ability of the electric grid to withstand and/or adapt to disruptive events such as extreme weather or equipment failures
Revenue Requirement	The total annual amount of money a regulated utility must collect from customers through rates to cover its expenses, while earning a return on investment
Tariff	A regulator-approved document that establishes the rates, rules, and terms of service governing how customers are charged for electric utility service
Transmission	The high-voltage network and related equipment used to move large quantities of electricity over long distances from generators to major load centers and substations. Transmission systems typically operate at high voltages to reduce losses and enable bulk power transfer.
Transmission Capacity	Maximum amount of electrical power, measured in megawatts (MW), that can be transferred across a transmission line
Variable Costs	Electric system costs that change based on the amount of electricity produced or delivered (e.g., fuel, operations & maintenance, and wholesale energy purchases)
Volumetric Rates	Electric rates where customers are charged based on the quantity of power they consume

Executive Summary

As the United States embarks on a critical phase of infrastructure modernization, the emergence of significant new electricity demands, particularly from the data center industry, have incited headlines across the country about rising retail electricity rates and customer bills. However, many of these headlines do not fully capture the underlying mechanics of how electric rates are set or distinguish between broader system cost trends and the incremental impacts of new large loads. They also often lack quantitative assessment of how emerging rate designs and tariff protections allocate costs and manage risk.

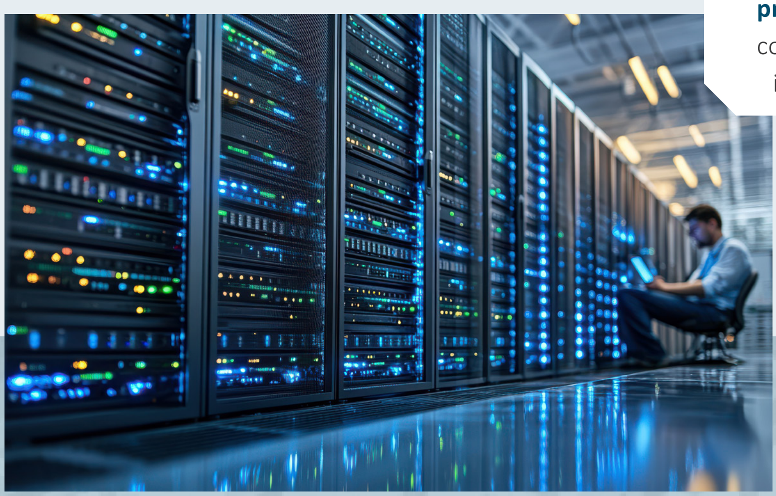
At the same time, there is growing policy and industry interest in improving utilization of the existing electric grid, with recent legislative activity and new analyses highlighting the potential for more efficient use of existing infrastructure to reduce costs for customers.

This paper places load growth in its proper context: data center-driven load growth presents an opportunity to bolster grid resilience and efficiency, yet the realization of these benefits is contingent upon effective load integration strategies and equitable pricing frameworks. This paper demonstrates how, under the right system conditions and rate structures, data centers can help mitigate upward pressure on rates due to their high-utilization load profiles, provided that modern large-load tariffs incorporate best practices and appropriate risk mitigation provisions. This analysis focuses on GS-5, Dominion's new large load tariff, which includes numerous of these best practices and ratepayer protections designed to prevent cost-shifting and mitigate stranded cost risk.

Despite increasing attention on this topic, important gaps remain in how large loads and their impacts are understood.

This paper seeks to address those gaps by:

+ **Clarifying common misconceptions** about the relationship between large loads and rising electricity rates, particularly the assumption that new demand necessarily increases costs for other customers
+ **Improving transparency** around how large-load tariffs are structured and how risks and costs are allocated between utilities, large customers, and other ratepayers
+ **Providing new quantitative analysis** to evaluate system impacts, including modeled outcomes under different scenarios of load growth and load uncertainty
+ **Highlighting historical context**, including how large, high-load-factor customers have traditionally supported system utilization and cost recovery
+ **Assessing the effectiveness of modern ratepayer protections**, such as minimum demand charges, collateral requirements, and contractual safeguards, in mitigating cost-shifting risks



Together, these contributions are intended to provide a more grounded, data-driven perspective on the role of large loads in today's evolving electric system.

Key Findings

1 A System Already in Transition

The electric grid is entering a period of increased investment driven by a range of structural factors that predate the recent acceleration in data center development. Much of the existing system, including infrastructure built in the 1960s and 1970s, is reaching replacement age, while electrification of buildings, transportation, and industry; domestic manufacturing reshoring; and growing needs for reliability, resilience, and system hardening are all contributing to ongoing infrastructure expansion. Many of these investment needs are arising independent of new large loads and reflect broader system trends already underway. As a result, data center growth is occurring within a grid that is already evolving and reinvesting, rather than being the sole driver of current investment activity.

2 Load Growth, Utilization, and Cost Outcomes Depend on System Conditions and Rate Design

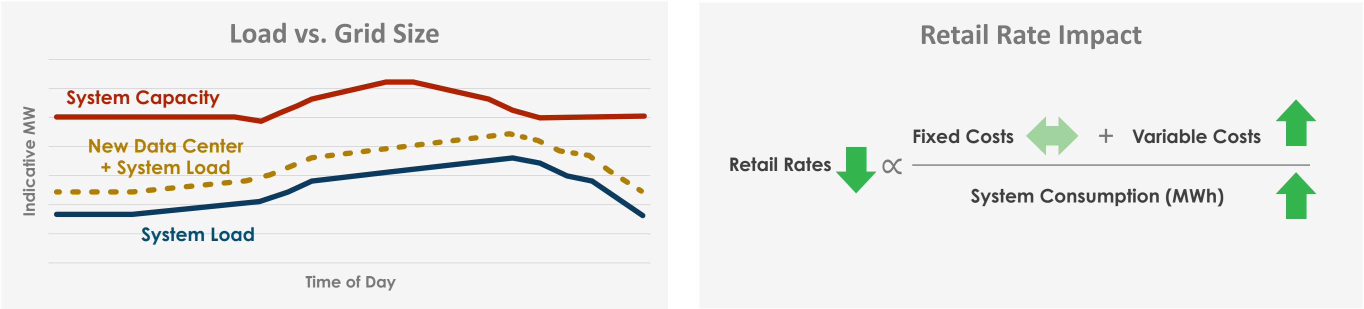
While retail electricity rates are rising due to a range of structural factors, under the right conditions large loads can help mitigate upward pressure on average system costs per unit of energy by contributing significant revenue toward fixed utility costs and increasing the volume of electricity sales over which those costs are recovered, particularly for generation and bulk system capacity. This is because data centers are high load factor customers. Load factor is defined as the ratio of average demand to peak demand over a given period. Data centers typically operate at a load factor of 80-90%, compared to the average residential load factor of 30-40%. At the same time, the incremental or marginal cost of serving new load can, in many jurisdictions, exceed the current average or embedded cost of the system, particularly where new capacity, transmission, or distribution investments are required. As a result, the overall cost impact of new large loads depends on the balance between their high utilization, which tends to lower average costs, and the incremental investments required to serve them.

All else equal, higher utilization of the system (i.e. higher load factor) lowers the average cost per kWh. How this translates into retail rates depends on cost allocation, rate design, and regulatory decisions, as marginal costs that influence prices may differ from average costs, particularly in systems with significant zero-marginal-cost resources or limited capacity headroom. In systems approaching capacity constraints, marginal costs may reflect the need for new and often more expensive infrastructure, while systems with excess capacity may be able to serve additional load at relatively low incremental cost. That said, there is evidence of a relationship between utilization and retail rates: a recent study from Lawrence Berkeley National Laboratory (LBNL) found that between 2019-2024, statewide load growth tended to reduce average retail electricity prices, primarily due to spreading fixed system costs over more kilowatt-hours.[1] Figure 1 illustrates this dynamic in a system with available headroom, where new load can be served without triggering additional infrastructure investment.

Even when new load increases system peak and requires additional generation, transmission, or distribution investment, the same principle can still apply; average system costs, and by extension likely average rates, can decline if the incremental revenue from new electricity sales exceeds the additional costs to serve that new load. However, this outcome is not guaranteed. Where marginal costs are significantly higher than embedded costs, new load can increase total system costs unless rate design ensures that those incremental costs are fully recovered from the customers driving them. The net effect depends on factors such as the magnitude of required investment and the load factor of the customer. High load factor customers, such as data centers, tend to increase total energy sales relative to peak demand, allowing fixed costs to be recovered over a larger volume of electricity.

In practice, this means that new capacity additions do not necessarily increase average rates. When new loads are large, operate at high utilization, and are supported by appropriate rate design, they can contribute to lower average system costs per kWh, even in scenarios where new infrastructure is required. However, outcomes vary by system and depend on the scale and timing of investment needs. Critically, this depends on aligning rates with cost causation so that prices reflect marginal cost signals while still enabling recovery of embedded costs, thereby avoiding cost shifts between customer classes.

Figure 1: *Illustrative Load vs. Grid Size and Retail Rate Impact*



Source: Energy and Environmental Economics, Inc. (E3), Ratepayer Impact Study, December 2025, https://www.ethree.com/wp-content/uploads/2025/12/RatepayerStudy.pdf

[1] Ryan Wiser, Eric O'Shaughnessy, Galen Barbose, Peter Cappers, and Will Gorman, "Factors Influencing Recent Trends in Retail Electricity Prices in the United States," *The Electricity Journal* (2025), https://www.sciencedirect.com/science/article/pii/S1040619025000612.

3 Best Practices in Modern Tariff Design Can Align Cost Responsibility and Protect Ratepayers

The impact of large new loads on other customers depends largely on how costs and risks are allocated through tariff design. Historically, there were limited standardized protections to ensure that large customers fully covered the costs they imposed on the system, and risks associated with load departure or underutilization were often borne by the broader rate base. Now, in contrast, a growing number of utilities have introduced dedicated large-load tariffs to introduce ratepayer protections and reduce cost-shifting risk. Twenty-five utilities across 19 states have approved data center-specific tariffs, with the majority (18) approved in 2024 and 2025 alone, and many more have been proposed in recent years or currently under review.[2]

These modern tariffs increasingly incorporate best practices such as minimum demand charges, long-term contracts, and collateral requirements to better align cost responsibility with cost causation and mitigate under-recovery risk. This paper evaluates how these mechanisms perform in practice using a hypothetical 100 MW data center under Dominion Energy Virginia's GS-5 tariff. For more details on key features and components of the GS-5 tariff, please see the Technical Appendix.

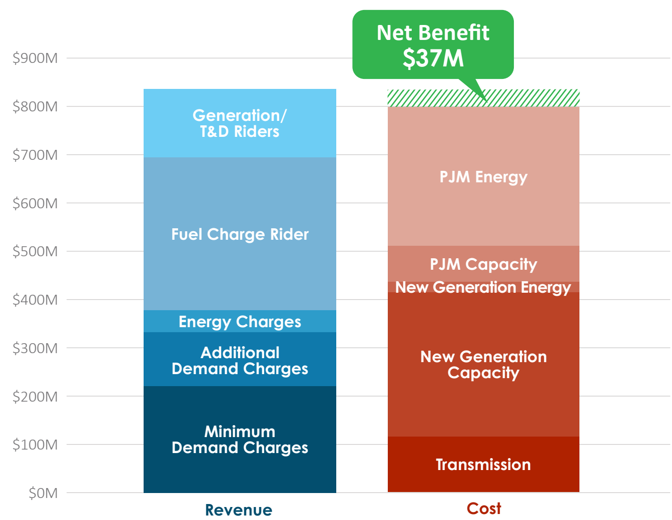
Cost Responsibility and System Contributions

First, the analysis explores whether an individual data center in Virginia, once operational, pays its full cost of service and contributes to system cost recovery. To evaluate this question, the paper examines a hypothetical 100 MW data center served under Dominion Energy's GS-5 tariff in Virginia. The results demonstrate how modern large-load tariff structures, like GS-5, can require customers to cover their cost of service and, in many modeled scenarios, contribute net revenues to the system. This analysis is conducted from a marginal cost perspective, comparing the incremental costs to serve the new load with the incremental revenues it provides.

The results demonstrate that modern large-load tariff structures, such as GS-5, can require customers to cover their cost of service and, in many modeled scenarios, contribute net revenues to the system. They also indicate that the provisions and protections under GS-5 are functioning as intended, helping ensure that the costs of serving this load are appropriately allocated without shifting costs to other ratepayers.[3] Under a reasonable representative base case scenario modeled for a hypothetical new 100 MW Virginia facility (i.e., the "Base Case"), revenues from the data center exceed the modeled costs to serve it, producing a net system benefit of $37M, or $0.000027 per kWh (Figure 2).[4] Sensitivity analyses showed a range of outcomes, from $166M in net benefits to $92M in net costs (Figure 3), depending on the underlying power generation supply mix and resource costs.[5]

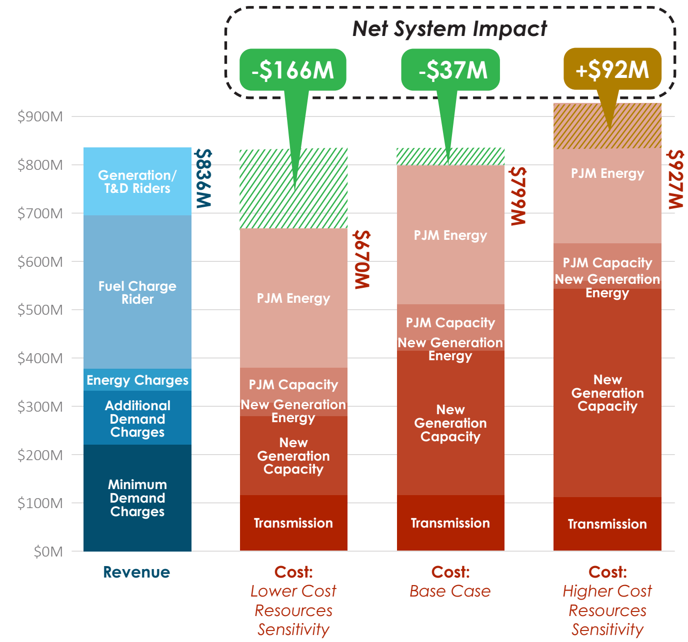
Overall, **across most modeled scenarios, revenues generated under the GS-5 tariff exceeded the modeled cost of service, resulting in net benefits for the system**. From this micro perspective, a "net benefit" indicates that the customer is contributing more in revenues than the incremental cost to serve it, thereby providing a contribution toward recovery of embedded system costs. In other words, under appropriate tariff design, an individual data center can not only meet its cost

***Figure 2:** Utility Costs vs. Revenues for Hypothetical 100 MW Data Center – Base Case (NPV 2025$)*



Note: These results represent conservative assumptions about the costs to serve the data center. It is assumed that there is no additional headroom on the Dominion Virginia system and that new generation and transmission capacity, including 5 miles of gas pipeline, had to be built to accommodate the data center load.

***Figure 3:** Utility Costs vs. Revenues for Hypothetical 100 MW Data Center – Base Case and Sensitivities (NPV 2025$)*



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[2] Latitude Media, "The Terms of Power: Inside the New Utility Rates for Data Centers," March 2026, https://www.latitudemedia.com/research/the-terms-of-power-inside-the-new-utility-rates-for-data-centers/

[3] The analysis tested many cases under GS-5, but did not explore other large load tariffs that have been proposed or adopted across the U.S.

[4] The Base Case assumes no additional headroom on the system, and that new capacity and transmission must be built to accommodate the 100 MW data center load. The resource mix assumed is 60% PJM market purchases, 10% utility solar, 10% gas CCGT (including 5 new miles of gas pipeline), 10% onshore wind, and 10% 4-hour battery storage. The resource mix is informed by the Dominion Energy Integrated Resource Plan (IRP). The $/kWh value assumes 100.2 million MWh of electricity delivered, consistent with 2025 sales.

[5] Costs are shown in net present value (NPV) over the asset lifetime in 2025 real dollars.

responsibility but also contribute positively to overall system cost recovery, rather than shifting costs to other customers.

Beyond simply covering its cost of service, a high load factor customer such as a data center can also improve the speed and certainty of cost recovery for utility investments. Because data centers often consume electricity at a relatively steadier rate than other customers, they can generate a higher and more predictable revenue stream per unit of capacity than lower load factor customers. As a result, for a given level of infrastructure investment, the "contribution margin" from a data center can accelerate the payback period. In the illustrative example below, the same 100 MW of capacity is assumed to be built to serve either a data center or an equivalent amount of residential load. Under the data center case, the investment is recovered in approximately 13 years, whereas it would take roughly three additional years under residential revenue assumptions (Figure 4).[6] This faster cost recovery can reduce financial risk for utilities and, in turn, lower the likelihood that costs are deferred or shifted to other customers. It's worth noting that this is a conservative case that assumes fast ramp-up for residential loads. If that ramp were to be slower, then the payback period would similarly extend.

Non-Payment Risk

Next, the analysis examines how collateral requirements mitigate non-payment risk for an individual data center. This scenario is not intended to represent full load departure, but rather a delay or initial failure in payment. Figure 5 compares the anticipated revenue generated from a new 100 MW data center with the level of collateral required under the GS-5 tariff.

The results show that, in the case of non-payment or delayed payment, required collateral from an investment-grade customer under GS-5 would cover most of the expected first-year revenues, while collateral requirements for non-investment-grade customers could exceed those anticipated revenues.

Managing Load Departure Risk

Finally, the analysis evaluates the extreme "worst-case" scenario in which the data center load never materializes, using the same hypothetical 100 MW data center under Dominion Energy's GS-5 tariff. At a system level, a key concern is that utilities may invest in generation, transmission, or distribution infrastructure to serve large new loads that are delayed, reduced, or never materialize. In such cases, portions of the system could become underutilized, with associated costs potentially borne by other customers.

Historically, the risk of large industrial load departure was largely borne by the broader rate base, with some limited protections such as minimum bills or negotiated contracts. In contrast, modern large-load tariff structures are designed to mitigate these risks through provisions such as exit fees, minimum demand charges, collateral requirements, and contractual obligations. These mechanisms help ensure that, even in cases of load departure, the cost exposure to other customers is limited and aligned with the risks created by the new load.

As shown in Figure 5, in the case of non-payment or delayed payment, the customer's collateral would be drawn upon and would cover most of the expected first-year revenues. If non-payment persists, however, the utility could face stranded asset risk. In practice, there are several mechanisms available to mitigate this outcome before reaching a worst-case scenario:

+ **Capacity reassignment:** The departing customer may identify a replacement customer to assume the associated capacity and financial obligations, which can reduce or eliminate exit fees.
+ **Notice period:** Customers may reduce their contracted capacity by up to 20% at no cost, or by up to 50% if a replacement customer is secured, provided they give 36 months' notice.

***Figure 4:** Investment Cost Recovery for 100 MW Capacity under Data Center vs. Residential Revenue Streams (2025$)*

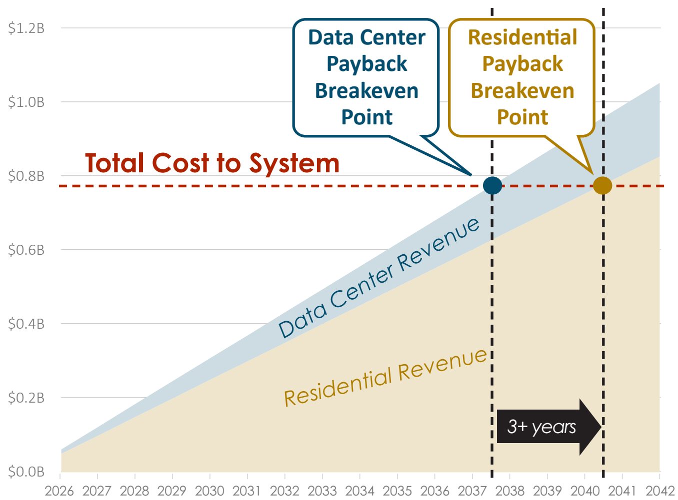
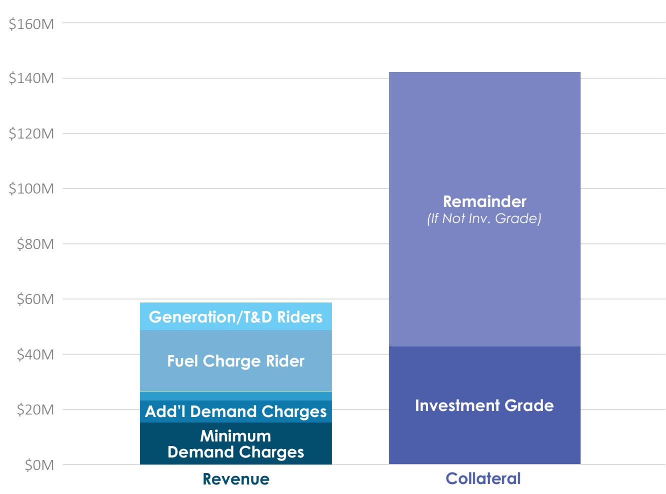


***Figure 5:** First-Year Anticipated Revenue vs. Required Collateral for Hypothetical Data Center (2025$)*



[6] See sections 9.2 and 9.6 of the Technical Appendix for more information about calculation of residential revenues and load shapes.

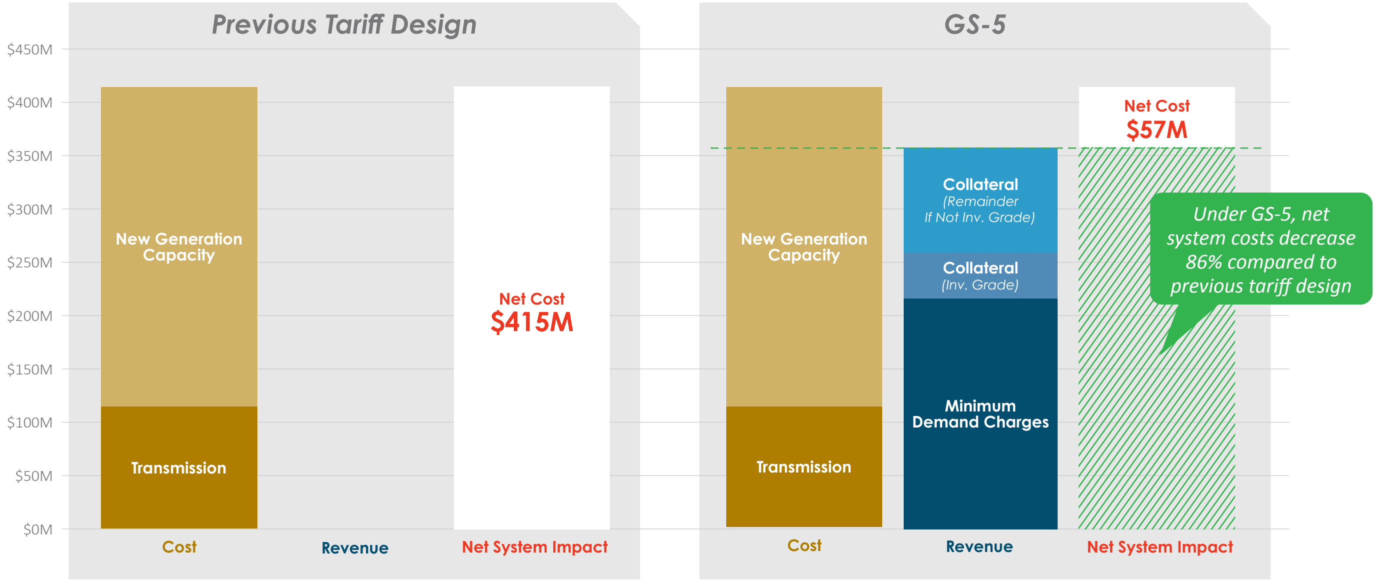
If non-payment continues and these options are not exercised, the remaining risk is addressed through contractual protections. Under Dominion's GS-5, the customer is responsible for a substantial exit fee, structured as minimum demand charges covering a 14-year contract period, payable upfront. This obligation is in addition to any collateral already posted.

Under the worst-case scenario of full load departure, the GS-5 tariff substantially improves cost recovery under a stranded asset situation and limits impacts to other rate payers. Modeled results suggest that these protections can reduce the net cost to the system by 86% compared to previous tariff design (Figure 6).[7] Even in this worst-case scenario, the resulting net cost would have a minimal impact on individual customers, increasing average retail rates by approximately $0.000042 per kWh on average.[8]

This demonstrates how robust tariff design can materially reduce the risk that other ratepayers bear the costs of investments made to serve large new loads. GS-5 incorporates a relatively comprehensive set of protections compared to historical approaches, where the costs associated with large load departure were more often borne by the broader rate base. As similar tariff structures continue to evolve across jurisdictions, the extent of these protections may vary.

In practice, this worst-case outcome is highly unlikely. Utilities and customers would likely pursue mitigation options first, such as repurposing capacity for another large user or selling excess capacity into the PJM market, further reducing cost shift risk.

Figure 6: *Revenues vs. Costs for Hypothetical 100 MW Data Center Under Complete Load Departure (NPV 2025$)*[9]



These findings can be understood across two related dimensions:

- **At the micro (project-level)**, the question is whether an individual large-load customer pays its cost of service and contributes to system cost recovery once operational.
- **At the macro (system-level)**, the key concern is how broader system risks are managed, including the potential for stranded or underutilized infrastructure if anticipated load does not materialize, as well as broader market impacts such as changes in wholesale prices.

This paper primarily focuses on the micro, project-level perspective, evaluating whether a large load customer pays its cost of service and contributes to system cost recovery under modern tariff design. It also examines one key macro-level risk: the potential for stranded or underutilized infrastructure if expected load does not materialize, and how tariff protections mitigate that risk.

Other macro-level considerations, including impacts on wholesale market prices, regional transmission expansion, and broader system cost allocation, are not the primary focus of this analysis. These issues are explored in more detail in E3's prior study for Virginia Joint Legislative Audit and Review Commission (JLARC), which examines how large load growth can affect market outcomes and system-wide costs.[10] Approaches to addressing those impacts, such as allocating a greater share of system costs to large loads, may be conceptually straightforward but involve important tradeoffs and implementation complexities.

[7] In practice, the capacity built for a data center that never comes online would likely be repurposed rather than fully abandoned, leading to additional revenue generated for the utility. The results shown in Figure 6 therefore represent the absolute worst-case scenario.

[8] Assuming 100.2 million MWh of electricity delivered, consistent with 2025 sales.

[9] There was the option for collateral under the previous rate design, but it was not mandatory like it is under GS-5.

[10] Joint Legislative Audit and Review Commission (JLARC), *Virginia Data Center Study* (Richmond, VA: JLARC, December 9, 2024), https://jlarc.virginia.gov/pdfs/presentations/JLARC%20Virginia%20Data%20Center%20Study_FINAL_12-09-2024.pdf

4 Implications for the Energy Transition and Resource Mix

As major purchasers of energy and anchor tenants for new infrastructure, data center operators are increasingly shaping the trajectory of the U.S. power system. In some regions and under certain procurement structures, they have supported the development of renewable energy and emerging "clean firm" technologies such as advanced nuclear and geothermal, helping to finance projects that might not otherwise move forward at scale. Their demand can accelerate investment in wind, solar, storage, and transmission, and in some cases help reduce integration costs that might otherwise be borne by other ratepayers. However, these outcomes are not uniform across regions and depend on local market conditions, resource availability, and procurement approaches. This underscores the importance of market design, resource planning, and policy frameworks in determining how new large loads are integrated into the system.

5 The Value of Grid Integration

While "islanded" or off-grid service is an alternative to grid integration, it is a missed opportunity to broader system benefits. Integrated data centers provide "anchor tenant" benefits; their participation ensures that the upgrades they fund, such as substation reinforcements and transmission hardening, strengthen the entire community's energy security rather than benefiting a single site in isolation.

Scope and Caveats

This paper evaluates large-load impacts against the backdrop of several established trends: an aging electric system requiring substantial reinvestment, accelerating demand growth from electrification and domestic industrial expansion, and growing interest in large-scale data center development. At the same time, important uncertainties remain. The timing, scale, and location of future load growth are not known with precision; nor is it yet clear what specific infrastructure investments will be required in all cases, what exact resource portfolios will be built to serve new demand, or how all costs and revenues will be allocated under future rate designs.

Accordingly, the analysis presented here is illustrative rather than predictive. It uses a hypothetical data center and a single proposed tariff framework to examine potential system outcomes under a defined set of assumptions. The paper is intended to inform the discussion around large-load tariffs and ratepayer protections, not to forecast the exact effect of future data center development in any single utility territory. This paper also does not address recent price fluctuations in the PJM capacity market.

Introduction

The United States is entering a critical phase of infrastructure modernization, accompanied by a surge in electricity demand, particularly from data centers. This trend has generated widespread attention, with many headlines linking load growth to rising retail electricity rates and customer bills. However, these narratives often lack important context. They do not fully reflect how electric rates are determined, nor do they clearly separate system-wide cost trends from the incremental effects of new large loads. In addition, they rarely provide a detailed, quantitative view of how evolving rate designs and tariff structures allocate costs and manage risk.

At the same time, there is growing interest among policymakers and industry stakeholders in maximizing the use of existing grid infrastructure. Recent legislative activity and analytical work point to the potential for improved system utilization to lower overall costs and deliver benefits to customers.

This paper places load growth in its proper context. While the expansion of data center demand introduces new planning and cost allocation considerations, it also creates an opportunity to improve grid efficiency and strengthen system performance. Achieving these outcomes depends on thoughtful load integration and equitable pricing frameworks. Under the right conditions, customers with high and consistent load profiles can contribute to more efficient use of grid assets, which can help moderate upward pressure on rates. These benefits are most likely to be realized where large-load tariffs are designed with clear best practices and appropriate safeguards.

The analysis centers on Dominion Energy's GS-5 tariff, which incorporates many of these best practices and design elements. The tariff includes a set of provisions intended to align cost responsibility with cost causation and to limit risks such as stranded assets. In doing so, it helps reduce the potential for costs associated with new large loads to be shifted onto other customers.

Despite increasing focus on this issue, key gaps remain in how large loads and their system impacts are understood. This paper aims to address those gaps by:

- Addressing common misconceptions about the relationship between load growth and rising electricity rates, particularly the assumption that new demand inherently increases costs for other customers
- Enhancing transparency around large-load tariff design and the allocation of costs and risks among utilities, large customers, and other ratepayers
- Presenting new quantitative analysis of system impacts under a range of load growth and uncertainty scenarios
- Providing historical context on the role of large, high load factor customers in supporting system utilization and cost recovery
- Evaluating the effectiveness of modern tariff protections, including minimum demand charges, collateral requirements, and contractual provisions, in limiting cost shifting risks.

Taken together, this analysis offers a more comprehensive and evidence-based perspective on the role of large loads in an evolving electric system.

Electric System Fundamentals and Utility Economics

Peak-Driven Infrastructure

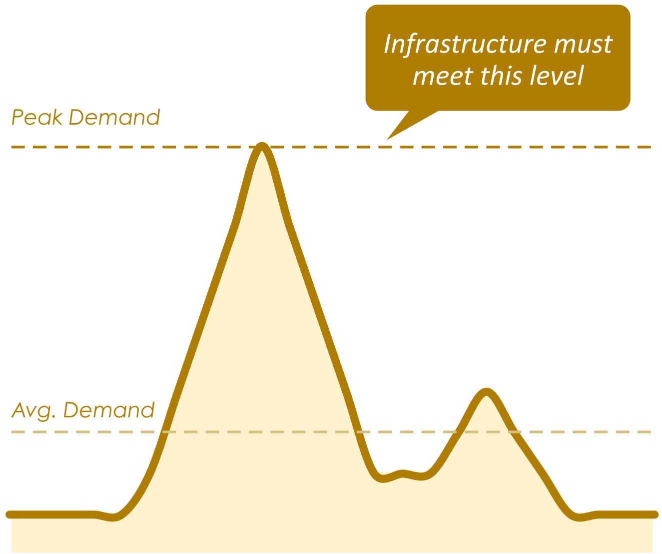
The North American electric system is a complex network of generating facilities, transformers, transmission lines, substations, and distribution lines that delivers electricity to end-use customers continuously and in real time. Because electricity cannot yet be stored at scale, supply and delivery must match demand at every moment. To maintain reliable service, electric utilities build sufficient generation, transmission, and distribution infrastructure to meet the highest anticipated electricity demand over the year, known as the system's "peak load."

The grid is designed to meet peak load because it represents the most demanding operating condition the system is expected to face. If there is enough generation and transmission capacity to serve maximum demand, there will necessarily be adequate supply and delivery capability during all lower-demand hours. Planning around peak demand is therefore central to reliability and helps prevent outages and service disruptions.

However, because the system is built to meet peak load, a relatively small number of hours each year drive the sizing of major infrastructure. As a result, the grid is underutilized for most hours of the year, effectively "overbuilt"relative to average demand. A helpful analogy is designing a city's stormwater drainage system to handle the volume of rainwater from a large downpour even though it will be far too large for the average rainfall, sitting underutilized most of the year.

The process for determining whether there is sufficient electric generating capacity to meet peak load is called resource adequacy (RA). To ensure RA, jurisdictions across North America apply established reliability planning standards to forecast peak demand and to determine how much capacity the system must have available to serve that demand. While reliability metrics vary by region, the most commonly used benchmark is the "1-in-10" Loss of Load Expectation (LOLE) standard. Under this standard, the system is planned so that the expected risk of a supply shortfall is limited to no more than one day in ten years, on average.[11]

Figure 7: *Illustrative Example of Peak-Driven Infrastructure*



[11] It is worth noting that there are other interpretations of the 1-in-10 metric (one loss of load event, one loss of load hour, etc.)

System Costs

Utility costs are often described as either fixed or variable. The electric system is highly capital-intensive: building and maintaining the grid requires significant investment, often billions of dollars upfront, to develop, operate, and maintain long-lived assets.

Fixed costs are those that do not vary meaningfully with short-run electricity consumption. Many fixed utility costs are driven by building and maintaining assets sized to meet peak load, including generation capacity, transmission and distribution infrastructure, substations, feeders, and transformers. Because the electric system is planned to meet peak demand (plus a reserve margin), a substantial share of capital investment is tied to providing capacity rather than serving average energy use. As a result, when customer usage is relatively peaky, the same amount of fixed cost must be recovered over a smaller volume of electricity sales, similar to the earlier stormwater drainage analogy, where infrastructure is built for the largest rainfall but then sits underused much of the time.

Generation capacity refers to the maximum power a resource can produce, typically measured in megawatts (MW). Transmission capacity refers to the amount of power a line or system can reliably transfer and is determined by factors such as thermal limits, voltage constraints, and stability requirements.

These large investments typically require long-term financing over asset lives that often span 30–50+ years. As a result, financing costs, such as interest rates, directly affect total system costs. Utilities recover these system costs through regulated electricity rates over time.

Variable costs include expenses that generally scale with electricity production and delivery, such as fuel and certain operations and maintenance costs.

To understand how these costs and investments translate into customer rates, it is helpful to understand the regulated utility revenue model.

Utility Financing

Revenue Requirement

Utilities are generally permitted to recover the prudent costs of providing service, plus an authorized return on capital invested to serve customers. These amounts are reviewed and approved by regulators, typically a state Public Utilities Commission (PUC), through periodic rate cases. The total annual amount a utility is authorized to collect from customers through rates is referred to as the revenue requirement.

Revenue Requirement = O&M + Capital Recovery + Taxes + Return on Capital

+ **O&M (Operations & Maintenance)** includes day-to-day operating expenses such as labor, materials and supplies, administrative costs, insurance, and routine maintenance. For utilities that do not own generation, O&M may also include purchased power and related operating expenses.
+ **Capital Recovery** is the annual recovery of the original capital investment in utility assets, typically collected through depreciation.
+ **Taxes** include federal/state income taxes, property taxes, and other fees.
+ **Return on Capital** compensates investors for providing financing.

Return on Capital = Rate Base × Allowed Rate of Return

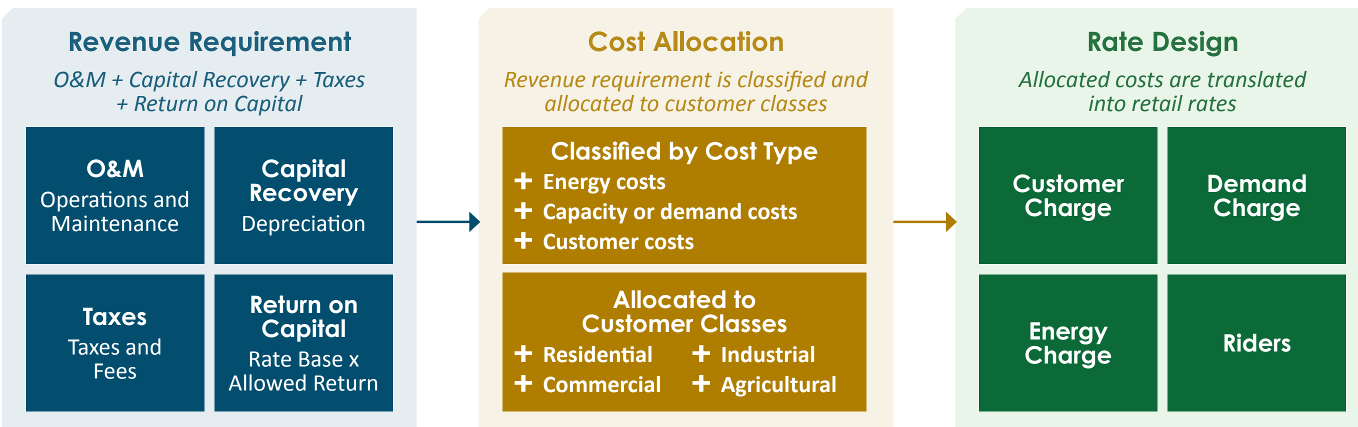
+ **Rate Base** is the net book value of utility plant used and useful in providing service (i.e., gross utility assets minus accumulated depreciation), spanning generation (where applicable), transmission, and distribution infrastructure. Because the grid is planned and built to meet peak demand, these investments are highly capital-intensive, and a large share of utility costs are tied to maintaining capacity rather than serving average energy use.
+ **Allowed Rate of Return** reflects the utility's approved financing costs, generally based on its cost of debt (interest rates on issued debt) and an approved return on equity, often weighted by the utility's authorized capital structure.

From Revenue Requirement to Rates

Retail electricity rates generally begin with the utility's approved revenue requirement (described above), which is then classified and allocated across different cost types and customer classes. As shown in Figure 8, costs are typically classified as energy, demand or capacity, customer-related, and in some cases riders that recover specific public policy or other approved program costs. Those costs are then allocated across rate classes, such as residential, commercial, industrial or large-load, and agricultural, generally with the goal of aligning cost responsibility with cost causation and producing "just and reasonable" rates.[12] While average rates can be approximated as allocated costs divided by electricity sales, rate design determines the specific charges customers actually pay, such as customer charges, demand charges, energy charges, and riders. In principle, this framework is intended to ensure that each rate class recovers the costs it causes, rather than shifting costs to other customer classes.

Because capital investment drives the rate base, and the rate base is a primary determinant of the revenue requirement, changes in capital spending can have a direct effect on rates. Total electricity sales also matter: holding costs constant, higher sales spread fixed costs over more kilowatt-hours (kWh), lowering the average cost per kWh, while lower sales concentrate those same costs over fewer kWh, increasing average rates.

Figure 8: *From Revenue Requirement to Rates*



Utility Regulation

Utilities are regulated entities, meaning that their spending plans and rates that they charge customers are reviewed and approved by the state Public Utilities Commission.[13] When a utility needs to update rates, it typically files a rate case requesting Commission approval of its proposed revenue requirement and the rates designed to recover that revenue from customers. As part of this process, the Commission evaluates whether the utility's costs and investments are prudent and whether the resulting rates are "just and reasonable", which is a standard intended to balance customer affordability with the utility's obligation to recover incurred costs and earn a fair, authorized return on invested capital.

Rate cases are formal, quasi-judicial proceedings. In addition to the utility and Commission staff, a range of stakeholders, known as intervenors, often participate. These stakeholders frequently include consumer advocates, large customers, municipalities, and other interested parties. The intervenors review the utility's filings, submit testimony, and may propose alternative cost or rate designs. The Commission then conducts hearings where utility and intervenor witnesses can be questioned and cross-examined. At the conclusion of the proceeding, the Commission issues an order approving, modifying, or rejecting the utility's proposals. The utility is required to comply with the order, and failure to do so can result in penalties.

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[12] National Association of Regulatory Utility Commissioners (NARUC), "Ratemaking Fundamentals and Principles," *Commissioners' Desk Reference Manual*, https://www.naruc.org/commissioners-desk-reference-manual/3-ratemaking-fundamentals-and-principles

[13] This discussion focuses on investor-owned utilities (IOUs); publicly owned utilities and electric cooperatives operate under different governance and ratemaking structures and are not the focus of this paper.

Load Factor

In the above sections we have discussed the foundations for electric system infrastructure design, utility financing, and ratemaking. This next section will build on these concepts to explore load factor and system utilization.

Introducing Load Factor: A Measure of System Utilization

Load factor is a measure of how efficiently electricity capacity is used. It is defined as the ratio of average demand to peak demand over a given period (e.g., a month or year). In other words, load factor indicates how steadily electricity is used relative to the customer's maximum demand.

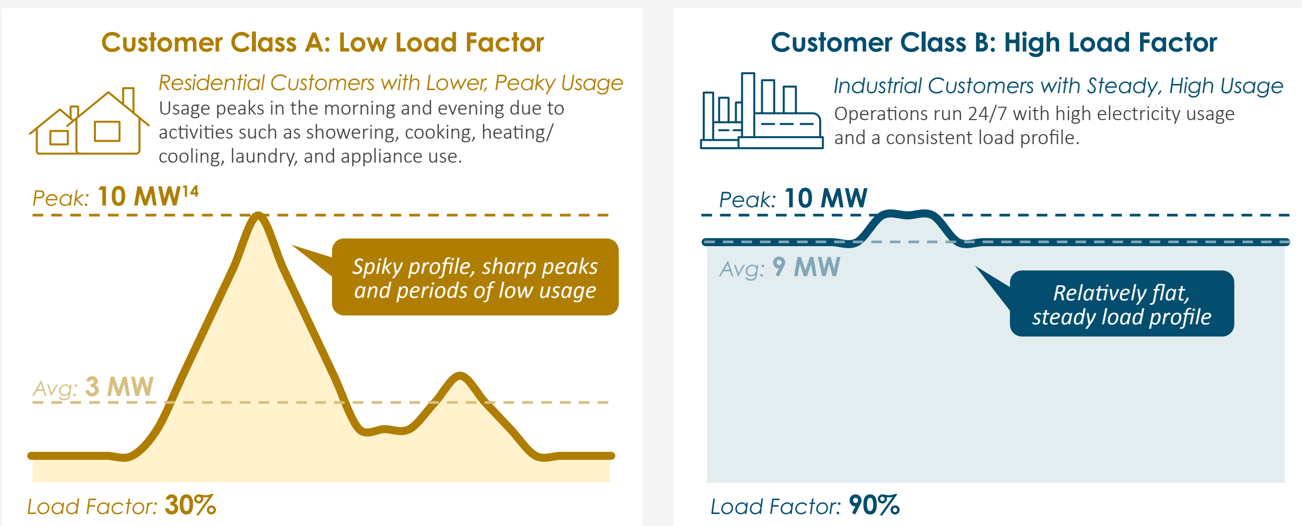
Load Factor = Average Demand ÷ Peak Demand

Using the stormwater drainage system analogy, load factor is similar to the average rainfall over the course of a year divided by the maximum water volume the drainage system can hold. The result reflects how fully, and how consistently, the drainage system is utilized.

Low vs. High Load Factor Customers

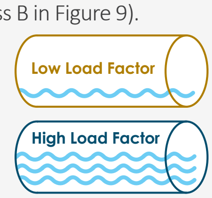
High load factor customers use electricity relatively steadily, with average demand close to peak demand. This is common for large industrial facilities with processes that run continuously. **Low load factor** customers use relatively little electricity most of the time but have short periods of high demand. This pattern is common for residential customers, whose usage often peaks in the morning and evening. Higher load factor is generally a more efficient use of the electric system because existing capacity is utilized more consistently.

Figure 9: *Illustrative Example for Low vs. High Load Factor Customer Types*



Customer Class A has a low load factor, while Customer Class B has a high load factor. Importantly, both customer classes require the system to be capable of serving 10 MW of peak demand, but Customer Class B uses that capacity much more consistently. Put another way, the grid must be built to the same peak capacity for both customer types, even though Customer Class B makes fuller use of that capacity across most hours (Figure 9).

Load factor matters because it indicates how efficiently a customer type utilizes grid infrastructure that must be sized to meet peak demand. Higher load factor customers tend to use the system more efficiently, even when their total electricity use is higher. Low load factor customers drive the need for capacity to serve short peak periods but use that capacity only briefly; thus during most hours, the infrastructure required to serve those customers is underutilized (Customer Class A in Figure 9). By contrast, high load factor customers may require a similar peak capacity buildout but use it more consistently over time, improving overall asset utilization (Customer Class B in Figure 9).



An intuitive analogy is two pipes of the same diameter: one carries water steadily and makes fuller use of its capacity, while the other experiences brief surges but runs mostly empty.

Low load factor customers contribute to underutilized electric infrastructure during off-peak hours because the system must still be built to serve their peak demand. By contrast, adding high load factor customers, whose demand is steadier and makes more consistent use of available capacity, can, under certain conditions, improve overall system utilization and increase the efficiency with which existing infrastructure is used.

[14] Numbers are for illustrative purposes only and not meant to represent realistic peak and average demand.

Why Load Factor Matters for System Economics

Load factor may also affect system economics and retail electricity rates. Because the grid is planned around peak load and a large share of utility costs are fixed, higher load factor customers can help spread fixed costs over more kWh. At the same time, the marginal cost of serving new load can differ significantly from the system's average or embedded cost, particularly in systems where new infrastructure or capacity additions are required. This distinction is important in evaluating how new load affects rates.

As a reminder:

> *Average Retail Rate = Revenue Requirement ÷ Total Electricity Sales*

If a high load factor customer increases steady electricity sales **without increasing peak demand** (and therefore without triggering new capacity-driven investments), that additional load can lower the average cost per kWh by spreading largely fixed costs over more sales. In this case, the marginal cost of serving the additional load may be relatively low, especially if existing generation and network capacity can accommodate it. However, if the customer's addition increases peak demand or requires new generation, transmission, or distribution upgrades (e.g., substations, feeders, and transformers), the revenue requirement may rise, potentially increasing rates. In these situations, marginal costs may exceed the system's current average cost, particularly if new investments are needed to maintain reliability or meet planning criteria. The net impact depends on local system conditions, timing, and cost allocation, and is discussed further in later sections.

More broadly, when incremental load can be served with existing infrastructure, high load factor customers can improve utilization of electricity assets. If significant new infrastructure is required, those benefits may be reduced or offset. In these cases, whether average system costs increase or decrease depends on whether incremental revenues from the new load are sufficient to cover higher marginal costs, as well as how those costs are allocated through rate design.

Large Loads

Defining Large Load: Then vs. Now

Large electric customers, often referred to as "large loads," are generally defined as customers with peak demand of roughly 20 MW or more.[15] Large loads have been interconnecting to the North American electric grid for a long time, but the characteristics of large loads have been rapidly shifting in recent years.

Large Loads: Then vs. Now

Figure 10: *Large Loads: Then vs. Now*

Then

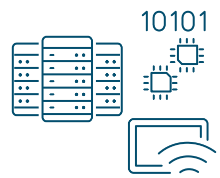
- Industrial customers
- 0-100 MW
- Cyclical
- Energy-intensive

Traditional large loads emerged during the mid-20th century industrial era and included manufacturing facilities, aluminum smelters, steel mills, chemical processing plants, refineries, and pulp or paper factories. These historical large loads were generally characterized by:

- High load factor and steady, continuous (24/7) operations
- Large, industrial-scale demand, often between 0 and 100 MW
- Commodity-expose economics, meaning revenues were largely set by competitive market prices outside the customer's control, limiting their ability to pass through costs
- Cyclical demand, with production and electricity consumption rising and falling with the broader business cycle and commodity price swings
- Significant contributions to volumetric revenue for utilities, increasing total kWh sales and, in some cases, improving utilization of existing infrastructure

→

Now



- Digital infrastructure, such as data centers and AI facilities
- 100-500+ MW
- Rapid growth
- Backed by highly capitalized firms

Modern large loads increasingly include data centers, artificial intelligence (AI) computing facilities, and cloud infrastructure. These emerging loads are often characterized by:

- Very large scale, with individual projects in the 100-500+ MW range
- High load factors, reflecting steady and around-the-clock electricity use[16]
- Long planning and development timelines, including multi-year site selection, interconnection, and construction horizons
- Strong credit support, often backed by highly capitalized firms that are, in some cases, willing to fund or prepay for dedicated electricity infrastructure

[15] Federal Energy Regulatory Commission, "Docket No. RM26-4," accessed March 2026, https://www.ferc.gov/rm26-4

[16] Some data centers may exhibit fluctuating or rapidly changing demand, including the potential for significant load reductions with limited notice. At the same time, many facilities are designed to operate at relatively high and consistent utilization levels.

Taken together, these characteristics are beginning to shape how modern large load customers engage with utilities and the broader electric system, including a growing willingness to assume greater responsibility for the costs they impose. This trend is particularly relevant in the context of marginal versus average costs, as it reflects an increasing emphasis on ensuring that new large loads cover the incremental costs required to serve them, rather than relying on embedded system averages. There have been several examples of large data center customers that have recently expressed a willingness, or made a public commitment, to fund electric infrastructure and mitigate potential rate impacts for other customers. As part of *Microsoft's Community-First AI Infrastructure* plan, the company has pledged to "pay its way" for data centers by paying utility rates intended to cover the costs of service and by working with utilities to enable the infrastructure needed to meet high electricity demand.[17] Anthropic has similarly committed to covering electricity price increases associated with their data centers, including paying 100% of grid infrastructure costs needed to interconnect their data centers, procuring new power, and investing in curtailment systems to reduce load during peak hours.[18] In a recent letter to Senators Elizabeth Warren of Massachusetts, Richard Blumenthal of Connecticut, and Chris Van Hollen of Maryland, Google said it intends to pay for all the electricity used to power its data centers and to adjust energy usage during the system's peak demand hours to minimize stress on the grid.[19]

These company-specific commitments are also being reinforced at the federal level. On March 4, 2026, several leading AI companies signed the White House's Ratepayer Protection Pledge, calling on signatories to "build, bring, or buy" the energy needed for their data centers and to pay the full cost of associated energy and infrastructure so that ratepayers are protected from load-driven price increases.[20] These types of commitments are consistent with a regulatory focus on aligning rates with cost causation, particularly in cases where marginal costs exceed average costs and require targeted recovery mechanisms.

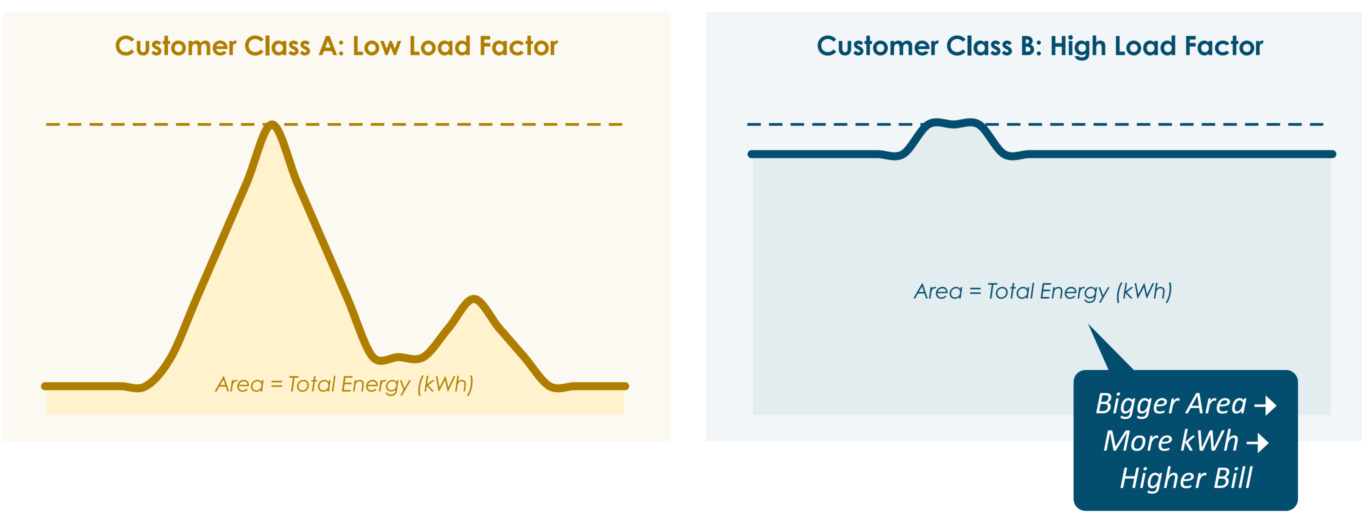
There is uncertainty about how consistently these commitments will be implemented and enforced across jurisdictions. Despite these uncertainties, the pledges do signal a meaningful shift in the profile of modern large loads: they're increasingly backed by highly capitalized firms that are publicly committed to pay for their power and infrastructure required to serve them.

Revenue Contributions and Cross-Subsidization Dynamics

How High Load Factor Customers Contribute More Revenue under Volumetric Rates

Under traditional volumetric rate designs (where much of a customer's bill is tied to \$/kWh × total kWh), customers that consume more electricity generally contribute more total revenue to the utility. High load factor customers often have higher electricity consumption, even if their load profile has less extreme peaks. As Figure 11 illustrates, the area under the load curve represents total electricity consumption. Under volumetric rates, higher total usage results in higher bills, meaning large-load customers contribute more revenue to the system overall.

Figure 11: *Total Electricity Usage for Illustrative Low vs. High Load Factor Customer*



[17] Brad Smith, "Community-First AI Infrastructure," *Microsoft On the Issues*, January 13, 2026, https://blogs.microsoft.com/on-the-issues/2026/01/13/community-first-ai-infrastructure/
[18] Anthropic, "Covering Electricity Price Increases," *Anthropic News*, accessed March 2026, https://www.anthropic.com/news/covering-electricity-price-increases
[19] Ella Nilsen, "Big Tech Faces Scrutiny from Elizabeth Warren over Electricity Use of Data Centers," *CNN*, January 22, 2026, https://www.cnn.com/2026/01/22/climate/big-tech-warren-electricity-data-centers
[20] The White House, "Ratepayer Protection Pledge," March 2026, https://www.whitehouse.gov/articles/2026/03/ratepayer-protection-pledge/

This dynamic also has important implications for cost recovery and investment risk. Because high load factor customers utilize infrastructure more consistently, they generate a larger and more predictable stream of revenues relative to the capacity required to serve them. In effect, this increases the "contribution margin" per unit of capacity, allowing utilities to recover fixed system costs more quickly.

For example, if a similar amount of capacity must be built to serve different customer classes, such as a high load factor class like data centers versus a lower load factor class like residential customers, the underlying infrastructure investment may be similar. However, the data center will consume significantly more energy over time and therefore generate more cumulative revenue under volumetric rates. As a result, the investment can be paid back more quickly, reducing the duration of cost recovery and lowering the risk that costs remain unrecovered.

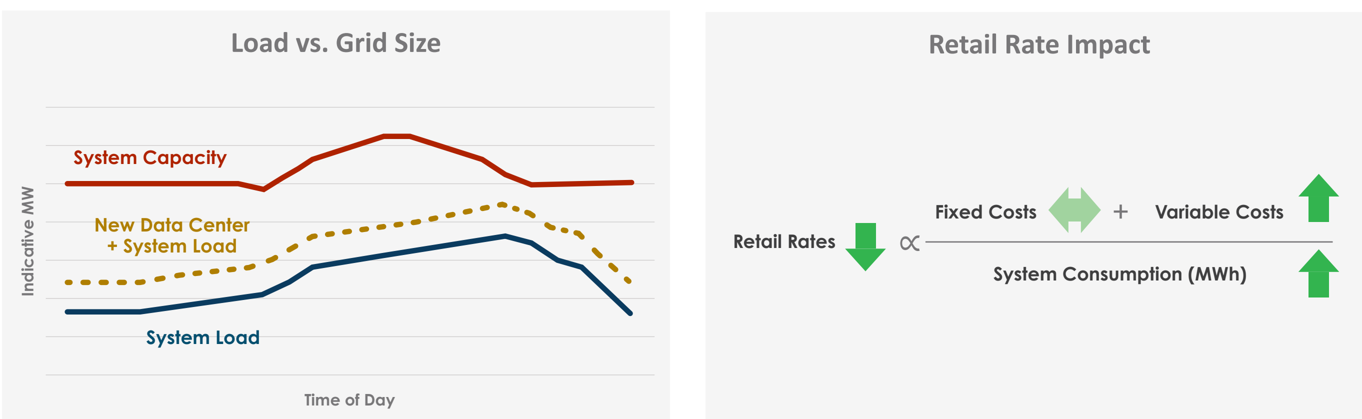
Large Loads and Public Policy Revenues

Because of their high electricity consumption and resulting revenue contribution, large-load customers can also make meaningful contributions to public policy programs through riders on electric bills. In 2023, for example, a hypothetical 100 MW large load customer would have contributed substantial funding toward Virginia policy measures that benefit the public, including roughly $3.5 million to the Regional Greenhouse Gas Initiative (RGGI) and $1 million through the Renewable Portfolio Standard (RPS) rider.[21] Those contributions are important context: large new loads do not only add demand to the system, they can also expand the revenue base supporting existing policy-related charges and help spread those costs over a larger set of kilowatt-hours.

Load Growth and Fixed-Cost Recovery

Furthermore, because a large share of utility costs is fixed or capacity-driven, such as embedded investments in generation and transmission, high, steady energy sales can help support fixed-cost recovery by spreading those costs over more kilowatt-hours. In that context, large, high load factor customers can sometimes function as an anchor for the system: they may contribute significant revenue that goes toward recovering past infrastructure investments, particularly if their addition does not lead to new system capacity requirements. This can have a downward pressure on rates, as shown in Figure 12.

Figure 12: *Illustrative Load vs. Grid Size and Retail Rate Impact*



Source: Energy and Environmental Economics, Inc. (E3), Ratepayer Impact Study, December 2025, https://www.ethree.com/wp-content/uploads/2025/12/RatepayerStudy.pdf

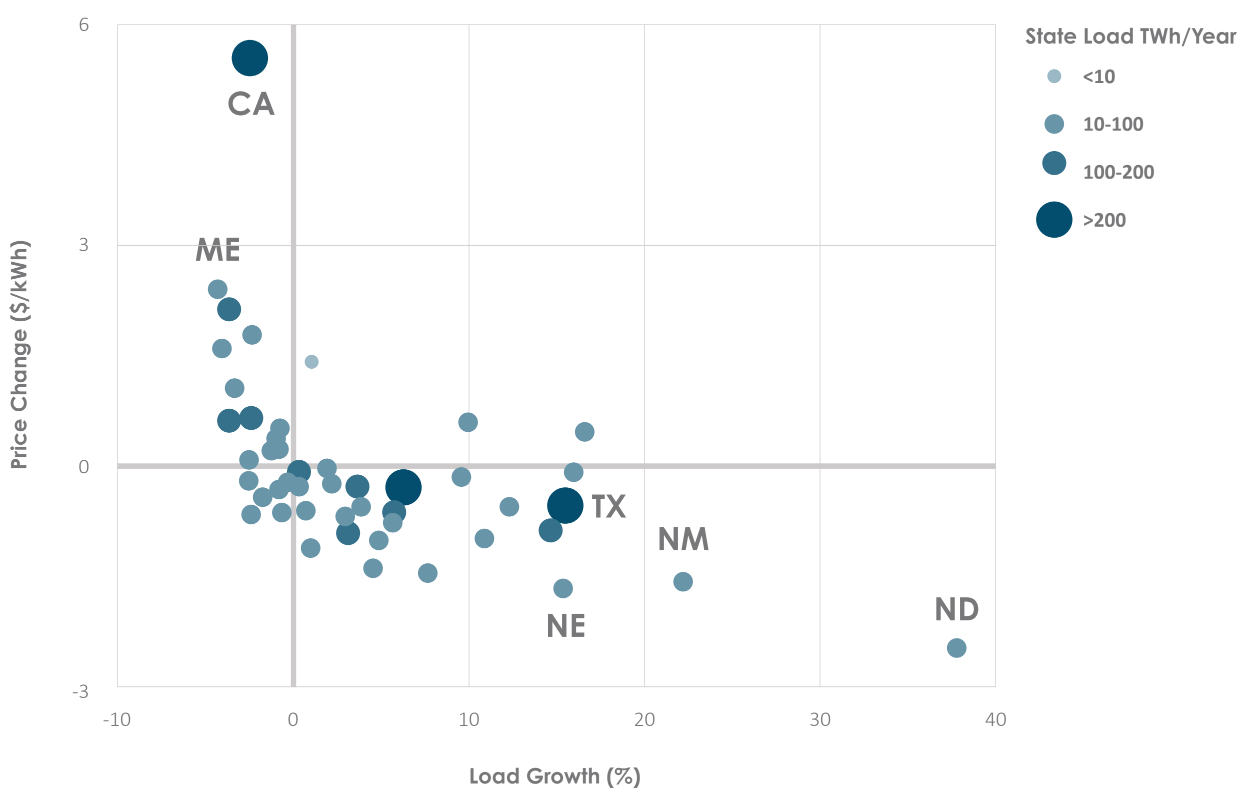
[21] These values were derived using the 2023 Dominion Energy Virginia RGGI and RPS rider details.

Evidence That Load Growth Can Reduce Average Per-Unit System Costs

Evidence of this dynamic has emerged in recent years, particularly under conditions where systems had available capacity to absorb incremental load. In 2023, for example, Dominion Energy Virginia reported overall customer rates were 16% below national and 22% below regional averages, at a time when Virginia represented nearly a quarter of total U.S. data center load.[22, 23, 24] Additionally, a **Lawrence Berkeley National Laboratory (LBNL) analysis found that, from 2019 to 2024, state-level load growth was generally associated with reductions in average retail electricity prices,** driven primarily by fixed utility costs being spread over more kilowatt-hour sales.[25] States with the largest increases in customer load often experienced declines in inflation-adjusted average electricity prices over the five-year study period. On average, LBNL found that a 10% increase in statewide load corresponded to a 0.6 cent/kWh reduction in electricity prices (Figure 13). The same study also cites Pacific Gas & Electric (PG&E)'s analysis in California, which found that an additional 10 GW of data center load could reduce customer electric bills by 10% or more.[26]

However, LBNL also emphasizes that these effects are not uniform across customer classes. The relationship is most apparent when looking at average system-wide prices, and is less pronounced when examining residential rates in isolation. This distinction highlights that while increased load can reduce average system costs, how those benefits are allocated across customers depends on rate design and regulatory decisions.[27]

Figure 13: *Relationship between Load Growth and Changes in Retail Electricity Prices from 2019-2024*



Source: Adapted from Ryan Wiser, Eric O'Shaughnessy, Galen Barbose, Peter Cappers, and Will Gorman, "Factors Influencing Recent Trends in Retail Electricity Prices in the United States," The Electricity Journal (2025), https://www.sciencedirect.com/science/article/pii/S1040619025000612.

22 Dominion Energy, "Dominion Energy Virginia, State Corporation Commission Staff, Office of the Attorney General, and Other Parties File Comprehensive Settlement of Biennial Rate Case," *Dominion Energy Newsroom*, 2023, https://investors.dominionenergy.com/news/press-release-details/2023/Dominion-Energy-Virginia-State-Corporation-Commission-Staff-Office-of-the-Attorney-General-and-Other-Parties-File-Comprehensive-Settlement-of-Biennial-Rate-Case/default.aspx

23 Electric Power Research Institute (EPRI), *Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption*, May 2024, https://www.epri.com/research/products/3002028905

24 Based on analysis done using MWh values from the EPRI Whitepaper, translated into MW assuming 85% load factor.

25 Ryan Wiser, Eric O'Shaughnessy, Galen Barbose, Peter Cappers, and Will Gorman, "Factors Influencing Recent Trends in Retail Electricity Prices in the United States," *The Electricity Journal* (2025), https://www.sciencedirect.com/science/article/pii/S1040619025000612

26 Pacific Gas and Electric Company, "PG&E Data Center Demand Pipeline Swells to 10 Gigawatts with Potential to Unlock Billions in Benefits for California," *PG&E Newsroom*, accessed March 2026, https://www.pge.com/en/newsroom/press-release-details.a9a4dda5-372f-4c33-860f-df2837e9b57b.html

27 Ryan Wiser, Eric O'Shaughnessy, Galen Barbose, Peter Cappers, and Will Gorman, "Factors Influencing Recent Trends in Retail Electricity Prices in the United States," *The Electricity Journal* (2025), https://www.sciencedirect.com/science/article/pii/S1040619025000612

New Capacity Can Still Lower Average Costs

The examples above reflect scenarios in which additional load can be served using existing system capacity. However, even when new load increases system peak and requires incremental investment in electric infrastructure, the same underlying principle can still apply: average system costs per kWh can decline if the incremental revenue from new electricity sales exceeds the cost of the new capacity required to serve that load.

This outcome depends on several factors, including the cost of new infrastructure, the amount of energy produced, and the utilization of that capacity over time. Load factor is particularly important in this context, as higher utilization allows fixed costs to be recovered over a larger volume of electricity sales.

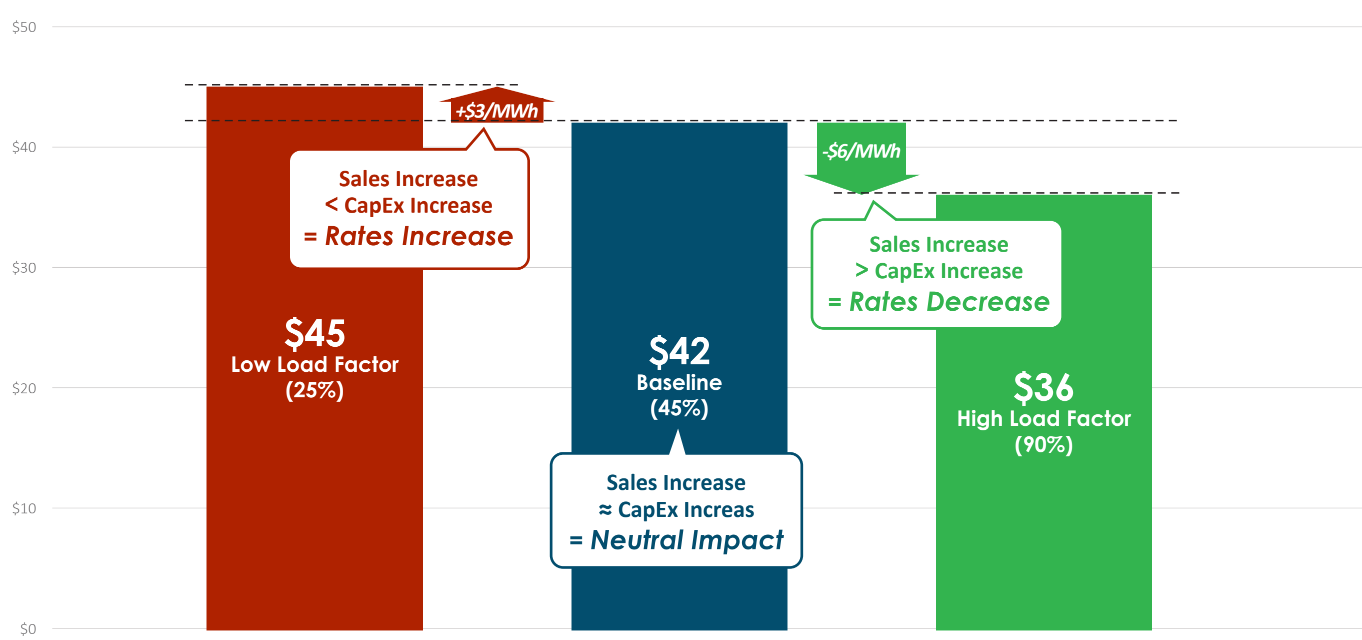
To illustrate this dynamic, consider a simplified, historical hypothetical example. Assume an addition of 5,000 MW of new capacity at an assumed capital cost of $1,000,000 per MW. At a baseline system load factor of 46% (approximately the current average in Dominion Energy Virginia), this level of capacity would serve roughly 20 million MWh of incremental energy annually (5,000 MW × 8,760 hours × 46%). When added to an assumed 100 million MWh of existing system sales, this results in total annual energy of approximately 120 million MWh, corresponding to an implied cost of about $42/MWh (Figure 14). Note that this example is intended to reflect a stylized, historical construct to demonstrate the underlying cost relationship and is not meant to represent current or forward-looking cost assumptions. As such, these inputs may differ from those used in the forward-looking case study of a new data center presented later in this report.

If the same capacity is driven by a high load factor customer (e.g., 90%), total annual energy served increases to approximately 139 million MWh. Because the fixed costs are spread over a larger volume of energy, the implied cost declines to about $36/MWh (Figure 14).

By contrast, if the capacity is driven by a low load factor customer (e.g., 25%, typical of many residential customers), the total annual energy served would be lower, and the implied cost would rise to approximately $45/MWh (Figure 14).

This example demonstrates that even when new infrastructure must be built, higher utilization can reduce average system costs per unit of energy. Whether these lower average costs translate into lower rates for specific customer classes depends on rate design, but the underlying cost dynamic remains: new capacity additions do not inherently increase average costs if they are supported by sufficient, high-utilization load.

Figure 14: *Cost for New Capacity under Different Load Factors ($/MWh)*



Rate Impacts Depend on Cost Allocation and Policy Design

It's important to note that these findings do not imply automatic cross-subsidization or guaranteed rate reductions going forward. The net rate impact will ultimately depend on rate design (e.g., demand charges vs. volumetric charges, minimum bills, special contracts), cost allocation, capacity auction impacts, whether incremental load triggers new infrastructure, and how regulators assign those incremental costs.

More broadly, whether load growth lowers or raises retail rates depends on the balance between incremental revenues and incremental costs, and on how those costs are allocated across customer classes through rate design and regulatory decisions. In some cases, as we have seen, new load can improve utilization of existing infrastructure and reduce average costs, as reflected in the LBNL study. In others, it can require substantial new generation, transmission, or distribution investment, increasing the utility's revenue requirement and putting upward pressure on rates, depending on how those costs are assigned across customer classes.

Impact of Large Loads on Utility Financing

Large loads also have the potential to affect utility financing and return on investment (ROI), but the evidence base is still limited and outcomes are highly uncertain, especially for rapidly growing modern loads like data centers. In principle, if load growth is sustained and predictable, it can improve revenue stability and strengthen cash flows, which are factors that credit rating agencies often view as credit positive. Over time, stronger and more stable cash flows may improve a utility's credit metrics, which could translate into a lower cost of debt and lower overall financing costs for infrastructure investments.

Credit analysts often focus heavily on cash-flow measures that indicate the ability for a utility to service debt and fund capital programs. The National Association of Regulatory Utility Commissioners (NARUC) training materials on utility credit ratings highlight metrics such as revenues relative to debt and discretionary cash flow as key indicators of credit quality.[28] In this case, a high load factor customer can be supportive if the incremental revenues are consistent and if tariff and contract structure reduce the risk of under-recovery or load departure.

Rating agencies similarly emphasize that predictability of earnings and cash flow is critical to credit strength. Fitch's published guide to credit metrics discusses cash flows as core inputs to credit assessment.[29] In a utility-adjacent example, Fitch's commentary affirming AES and its U.S. utility subsidiaries notes that stable, long-term contracted and regulated earnings and cash flow, along with supportive regulation, underpin ratings and outlook.[30] The key caveat is that none of these dynamics are automatic: if large-load growth drives major new capital spending, or if load turns out to be volatile or short-lived, financing needs and risk can rise, potentially offsetting any cash-flow benefits. This is why the credit and rate outcomes depend heavily on customer cost allocations, tariff design, market conditions, and regulatory treatment, rather than load growth alone.

Because the revenue requirement includes a return on capital, and a component of that return reflects the utility's cost of debt, improvements in borrowing costs can flow through to total system costs over time. That said, this outcome is not guaranteed. The net effect depends heavily on (i) whether the new load drives significant incremental capital investment, (ii) how those costs and risks are allocated to customers through tariffs and contracts, (iii) market conditions (including interest rates), and (iv) regulatory treatment. In some cases, large loads can increase required investment and, depending on cost allocation, put upward pressure on rates, which is discussed further in later sections.

[28] National Association of Regulatory Utility Commissioners (NARUC), *Utility Credit Ratings and Equity Analysis*, 2016, https://pubs.naruc.org/pub.cfm?id=C83A5224-A32B-9261-B07E-D241E933D900

[29] Fitch Ratings, *Guide to Fitch's Credit Assessment Framework*, n.d. https://images.ctfassets.net/03fbs7oah13w/7agnLMdXSM0mpn6gF5TF0H/2f157def126bd82770bba621279bf29e/Guide_to_Fitch_CAF.pdf

[30] Fitch Ratings, *Fitch Affirms Ratings on AES and U.S. Utility Subs; Outlook Stable*, June 28, 2024. https://www.fitchratings.com/research/corporate-finance/fitch-affirms-ratings-on-aes-us-utility-subs-outlook-stable-28-06-2024

Current State of the Electric Grid

The electric grid is currently facing a convergence of stressors, and is entering a cycle of new investment, even absent emerging large loads. Multiple, independent pressures, including replacement of aging infrastructure, grid modernization efforts, reliability and resilience upgrades, and transmission expansion, are driving capital spending in the electric system. Modern large loads interact with, and in some cases accelerate, these trends, but many of the grid's investment needs are driven by factors that are at least partly independent of incremental load growth.

Aging Infrastructure

Much of the electric grid infrastructure was built as long as 50-75 years ago. Assets typically have service lives on the order of 50-80 years, meaning a significant portion of the electric power grid is approaching, or has reached, its end of life. Across the power sector, aging infrastructure is widely cited as a leading challenge. For example, in a survey of the Institute of Electrical and Electronic Engineers (IEEE) Power & Energy Society members, 46% identified aging infrastructure as a top challenge for the energy industry.[31] The American Society of Civil Engineers (ASCE) also assigned U.S. energy infrastructure a D+ grade it its most recent report.[31]

Replacing aging grid infrastructure is therefore a major industry priority, given the risks and consequences associated with equipment deterioration and failure:

+ **Reliability and outages:** Aging equipment has a higher risk of failure, which can contribute to localized disruptions or, in some cases, widespread outages. Power interruptions can significantly disrupt daily life and critical end uses such as lighting, heating and cooling, refrigeration, communications, and medical devices.
+ **Safety and public risk:** Degraded infrastructure can create safety hazards, including fire risks. In high-risk regions, equipment failures have been linked to the start of wildfires. During outages, increased reliance on generators and alternative heating sources can also elevate risks such as carbon monoxide poisoning and house fires. Aging assets can pose occupational hazards for workers who operate and maintain grid equipment.
+ **Critical services disruption:** Power outages can interrupt essential services, including hospital and medical operations, water and wastewater systems, emergency response, and communications networks.
+ **Efficiency and losses:** Older infrastructure may operate less efficiently due to wear-and-tear and outdated standards. This can contribute to higher line losses, voltage issues, and broader operational inefficiencies across the power system.

Infrastructure across all types of assets needs replacement and upgrades.

+ **Transmission** represents the high-voltage portion of the power system that moves large quantities of electricity across long distances and delivers it to local substations where it can be stepped down for distribution to homes and businesses. About 70% of U.S. transmission lines are over 25 years old, approaching their end of life.[33] In addition, a 2022 ACORE (American Council on Renewable Energy) report finds that an estimated 200,000 miles of existing transmission lines across NERC regions will require replacement over the next 10 years, based on an extrapolation of AEP transmission replacement needs.[34] Many transmission assets were designed decades ago for different load patterns and system conditions, and aging equipment can increase the risk of failures that contribute to outages, and create public safety hazards such as fires.
+ **Transformers** manage voltage levels for electricity transmission and distribution. Many of the grid's transformers in use are beyond their standard lifetime.

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[31] IEEE Power & Energy Society, "2025 IEEE PES Global Survey Insights," accessed March 2026, https://ieee-pes.org/climate-change/2025-ieee-pes-global-survey-insights/

[32] American Society of Civil Engineers, "Infrastructure Report Card," accessed March 2026, https://infrastructurereportcard.org/

[33] U.S. Department of Energy, Grid Deployment Office, "What Does It Take to Modernize the U.S. Electric Grid?," accessed March 2026, https://www.energy.gov/gdo/articles/what-does-it-take-modernize-us-electric-grid

[34] American Council on Renewable Energy (ACORE), *Advanced Conductors to Accelerate Grid Decarbonization*, March 2022, https://acore.org/wp-content/uploads/2022/03/Advanced_Conductors_to_Accelerate_Grid_Decarbonization.pdf

A Department of Energy (DOE) report from April 2014 reported that the average age of large power transformers in the U.S. is 38-40 years, with 70% being 25 years or older, and this report was published over 10 years ago.[35] The DOE also refers to transformers as "one of the most vulnerable components of the grid", stating that the loss of transformer function could lead to widespread service disruptions.[36]

+ Many **distribution assets**, such as poles, wires, and feeders, and **distribution substations**, which step down high-voltage transmission to lower voltages for local delivery, are also reaching the end of their useful lives and increasingly require replacement. This infrastructure is essential to customer reliability: failures of key components can disrupt service for large numbers of customers and, in some cases, contribute to broader outages.

Aging, deteriorating equipment is creating a growing replacement backlog across the grid, largely independent of load growth. Utilities and regulators are already planning for and investing in asset replacements as part of baseline infrastructure renewal, even absent large new load additions. New load growth may interact with these efforts by accelerating timelines, changing equipment upgrade priorities, or increasing the scope of replacements, even though the underlying replacement need exists regardless of load growth.

Grid Modernization

Aging infrastructure is not the only pressure facing the grid. Even if all electric equipment was new, the grid would still require upgrades due to changing operational conditions and requirements.

The grid today is more complex than in the past, reflecting a range of evolving technologies and uses. This includes the growing presence of **distributed energy resources (DERs)**, such as rooftop solar, behind-the-meter batteries, demand response programs, and EV charging. While these resources provide important benefits and new capabilities, they also change how power flows on the distribution system and increase the number of devices that utilities must monitor and coordinate.

The grid is also facing **modernization requirements** to improve visibility and control, to protect against security risks, and to streamline interconnection processes.

Utilities are adding equipment to help see conditions in near real time and respond quickly. These systems include advanced metering infrastructure (AMI) and data systems, distribution sensors to monitor voltage and faults, and robust communication networks. Grid modernization efforts also include upgrades to improve cyber and physical security, such as improved encryption across communication paths, redundancies for key components like transformers, and surveillance for faster detection of security breaches or equipment failures. Modernization efforts also include improving processes and system upgrades to make it faster and easier to interconnect new customers and new resources. These improvements include workflow automation, better distribution and transmission planning integration, and updated on feeder capacity and load forecasts.

[35] U.S. Department of Energy, *Large Power Transformers and the U.S. Electric Grid: An Update*, April 2014, https://www.energy.gov/sites/prod/files/2014/04/f15/LPTStudyUpdate-040914.pdf

[36] U.S. Department of Energy, Office of Electricity, "Addressing Security and Reliability Concerns for Large Power Transformers," accessed March 2026, https://www.energy.gov/oe/addressing-security-and-reliability-concerns-large-power-transformers

Resource Transition and Generation Requirements

The U.S. power system is also in the middle of a significant resource transition, as older generators retire and the mix shifts towards cleaner resources. Despite these shifts, the grid must maintain resource adequacy and operational reliability as the characteristics of the generation fleet change.

A major driver has been coal retirements, which are occurring for both economic and environmental reasons. Economically, many coal units face high operating and maintenance costs and compete against lower-cost alternatives; environmentally, compliance obligations under laws like the Clean Air Act[37] and state decarbonization mandates (e.g., Illinois' Climate and Equitable Jobs Act and New York's Climate Leadership & Community Protection Act) have accelerated the transition. Looking ahead, EIA reports that owners plan to retire nearly 11 GW of utility-scale capacity in 2026, with 58% coal and 42% natural gas (steam turbine and simple-cycle units).[38] The DOE under the Trump Administration has issued emergency orders to temporarily postpone the retirements, but those delays are likely to be temporary and do not eliminate the underlying economic and policy pressures driving coal retirements.[39]

Retirements are not limited to coal. Older gas and other fossil fuel units also face increasing maintenance needs, poor performance under extreme conditions, and higher costs to meet evolving environmental and operational requirements.[40] As these units age, they may be less flexible and require more capital to remain reliable. When retirements occur at the same time as electricity demand is rising, the system can experience tighter planning margins, increasing the need for replacement dispatchable capacity and flexible resources.

At the same time, renewable energy is growing quickly due to a combination of market forces and policy. Over half of U.S. states have adopted some form of renewable portfolio standard (RPS) or clean electricity standard (CES), despite no federal standard for clean generation.[41] An LBNL analysis in 2023 found that almost half of the growth in renewable generation and capacity since 2000 can be associated with state RPS requirements.[42] Because renewable resources like wind and solar generate electricity on a variable basis, higher renewable shares on the grid generally increase the need for flexibility, such as energy storage and demand response. An increase in renewables can also shift where generation is located, which can drive transmission expansion needs.

These resource shifts are driving a new set of planning and investment requirements in the power sector: replacing retiring capacity, ensuring sufficient dispatchable and flexible energy to balance variable resources, expanding transmission infrastructure to account for different generation locations, and updating resource adequacy frameworks to reflect the evolving contribution of different resource types.

[37] Rebecca J. Davis, J. Scott Holladay, and Charles Sims, "Coal-Fired Power Plant Retirements in the United States," *Environmental and Energy Policy and the Economy 3*, no. 1 (2022): 4–36, https://doi.org/10.1086/717217

[38] U.S. Energy Information Administration, "Retirement Delays of U.S. Electric Generating Capacity May Continue in 2026," *Today in Energy*, February 23, 2026, https://www.eia.gov/todayinenergy/detail.php?id=67206

[39] Claire Brown and Brad Plumer, "Trump Wants to Halt Almost All Coal Plant Shutdowns. It Could Get Messy.," *New York Times*, January 16, 2026, https://www.nytimes.com/2026/01/16/climate/trump-coal-plants.html

[40] ISO New England, "Power Plant Retirements," accessed March 2026, https://www.iso-ne.com/about/where-we-are-going/power-plant-retirements

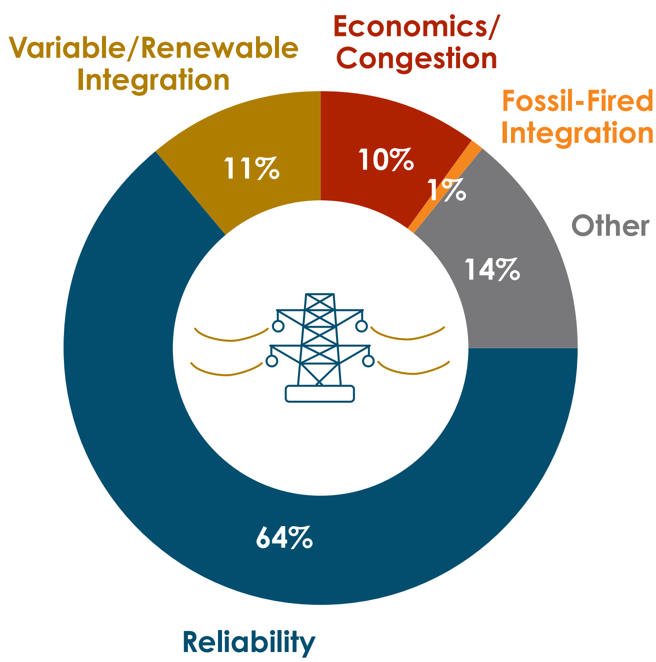
[41] U.S. Energy Information Administration, "Renewable Portfolio Standards," *Energy Explained*, last modified April 18, 2023, https://www.eia.gov/energyexplained/renewable-sources/portfolio-standards.php

[42] Lawrence Berkeley National Laboratory, "U.S. State Renewables Portfolio and Clean Electricity Standards," June 2023, https://emp.lbl.gov/publications/us-state-renewables-portfolio-clean

Transmission Constraints and Expansion Needs

Like generation, transmission needs are also rising regardless of the addition of new large loads. Growth in transmission investment is being driven by several factors, including the need to connect new renewable generation to the bulk power grid, strengthen reliability and resource adequacy, improve resilience, and address congestion.[43] Renewable and other clean energy resources are often developed in remote areas that are far from major load centers and existing transmission corridors; transmission expansion can enable these resources to interconnect and deliver energy to where it is needed. Reliability is also a major driver: NERC has reported that reliability is the primary stated purpose for planned transmission projects, with 64% of planned circuit miles intended to enhance reliability (Figure 15).[44] In addition, interregional high-voltage transmission can enhance resiliency by further reducing line losses, improving system stability, and supporting faster recovery after disruptions.[45] Transmission enhancements can also reduce congestion, which occurs when transmission constraints how much power can flow through the system. Interregional transmission expansion can also help reduce costs by enabling access to lower-cost generation across a wider footprint and by allowing neighboring systems to share energy and reliability resources more efficiently.[46]

Figure 15: *Future Transmission Circuit Miles by Primary Driver*



Source: North American Electric Reliability Corporation (NERC), 2021 Long-Term Reliability Assessment, December 2021, https://www.nerc.com/globalassets/programs/rapa/ra/nerc_ltra_2021.pdf.

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[43] U.S. Department of Energy, *National Transmission Needs Study*, December 1, 2023, https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf

[44] North American Electric Reliability Corporation (NERC), *2021 Long-Term Reliability Assessment*, December 2021, https://www.nerc.com/globalassets/programs/rapa/ra/nerc_ltra_2021.pdf

[45] Federal Energy Regulatory Commission staff, *Report on Barriers and Opportunities for High Voltage Transmission: A Report to the Committees on Appropriations of Both Houses of Congress Pursuant to the 2020 Further Consolidated Appropriations Act*, June 2020, https://www.congress.gov/116/meeting/house/111020/documents/HHRG-116-II06-20200922-SD003.pdf

[46] U.S. Department of Energy, "Transmission Impact Assessment," *Office of Policy*, accessed March 20, 2026, https://www.energy.gov/policy/articles/transmission-impact-assessment

Reliability and Resilience Pressures

Reliability and resilience needs are increasingly driving baseline grid investments, independent of any single source of new load. On the reliability side, the bulk power system is subject to mandatory, enforceable reliability standards overseen by the Federal Energy Regulatory Commission (FERC) and developed/enforced by North American Electric Reliability Corporation (NERC). Utilities must invest in systems, operating procedures, and infrastructure upgrades to maintain compliance and meet reliability standards. At the same time, RA concerns are becoming more prominent as peak demand grows, extreme weather increases, and dispatchable power plants retire. NERC's 2023 Long-Term Reliability Assessment highlights elevated RA risks across much of North America, reflecting tighter reserve margins and emerging energy risks in many regions.[47] As renewable penetration rises, planners are also re-examining RA methods and standards to better capture the contribution of variable resources and the growing need for load flexibility.

Resilience pressures, particularly from extreme weather and wildfire risk, are further accelerating grid investment. Utilities are increasingly spending on measures that reduce the likelihood of storm damage and accelerate restoration times, such as hardening vulnerable infrastructure and improving operational preparedness. In high wildfire-risk areas, utilities are also expanding mitigation programs to reduce ignition risk and improve situational awareness.[48, 49]

Summary

Taken together, it is clear the grid is entering an investment cycle that would be underway even without the addition of new large loads. Utilities are investing to replace aging equipment, modernize distribution systems, expand and improve transmission, and increase reliability and resilience in the face of more extreme weather and a changing resource mix. Recent national data underscore how central these "business-as-usual" drivers have become: LBNL finds that distribution is now the single largest source of utility capital spending, 44% of total capital expenditures in 2023, and that distribution capital spending grew ~50% from 2019 to 2023, reflecting replacement and modernization needs.[50] Transmission investment has also increased, with LBNL reporting 2023 transmission capital investments up ~20% from 2019.[51]

Because utilities recover these investments through regulated electricity rates over time, rising capital spending can place upward pressure on retail rates, particularly if electricity sales do not grow fast enough to spread fixed costs across more kilowatt-hours. In other words, the system is already constrained by infrastructure replacement backlogs, modernization requirements, resource transition needs, reliability and resilience obligations, and long transmission lead times, creating physical and planning constraints that exist independent of new large loads.

The next section examines the current demand acceleration from electrification, reshoring, and data centers, and how that growth interacts with these baseline conditions, especially with respect to near-term rate impacts and ratepayer protections.

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[47] North American Electric Reliability Corporation (NERC), *2023 Long-Term Reliability Assessment*, December 2023, http://nerc.com/globalassets/programs/rapa/ra/nerc_ltra_2023.pdf

[48] North American Electric Reliability Corporation (NERC), *Wildfire Mitigation Reference Guide*, July 2025, https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/wildfire_mitigation_ref_guide_july2025.pdf

[49] U.S. Department of Energy, *Current Practices in Distribution Utility Resilience Planning for Wildfires*, October 2024, https://www.energy.gov/sites/default/files/2024-10/UtilityResiliencePlanningPracticesforHazards-Wildfire.pdf

[50] Lawrence Berkeley National Laboratory, *Retail Electricity Price and Cost Trends: 2024 Update*, December 2024, https://eta-publications.lbl.gov/sites/default/files/2025-01/retail_price_and_cost_trends_2024_update_final_v3.pdf

[51] Ibid.

Current Demand Acceleration and Rate Implications

Current Demand Acceleration

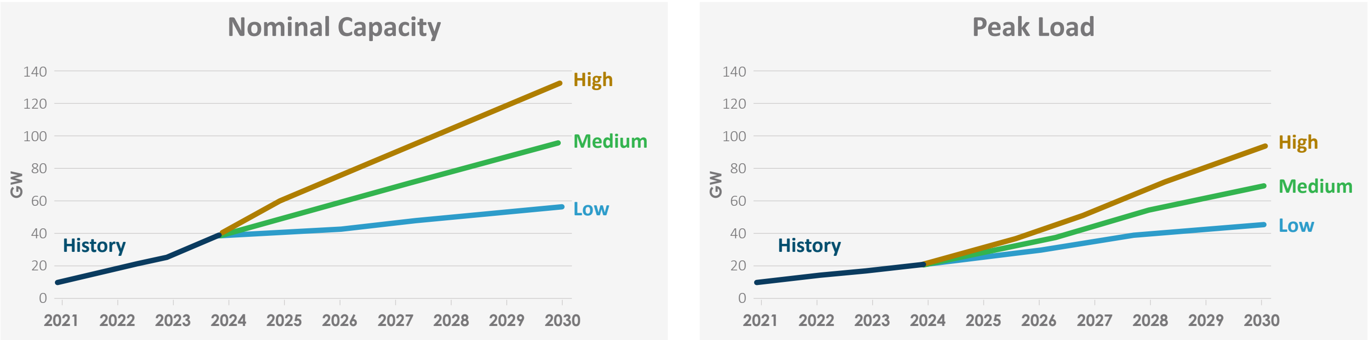
On top of these baseline conditions, the electric grid is also facing significant new electricity demand growth, driven by widespread electrification, reshoring and industrial growth, and AI data centers.

Electrification is the process of transitioning fossil fuel equipment to all-electric alternatives, such as switching from gasoline-powered internal combustion engine vehicles to electric vehicles (EVs) and switching from natural gas-powered furnaces to heat pumps. Buildings, transportation, and industry are already starting to electrify, with deeper electrification projected to occur to meet state and local climate goals, and, in some cases, due to economic benefits of transitioning. The Reference Demand Growth trajectory from the National Laboratory of the Rockies (NLR) 2024 Standard Scenarios Report shows that by 2050, 60% of final energy consumption by light-duty vehicles could be powered by electricity, compared to 1% in 2024.[52, 53] The same scenario from NLR estimates that 21% of residential space heating and 40% of residential water heating could be met by electricity by 2050.[54] At the same time, a share of U.S. industrial energy use is expected to shift toward electricity as manufacturers adopt electric process heat and electrify certain thermal systems, though the pace and extent of industrial electrification will vary widely by subsector and technology readiness.

Another driver of recent and future load growth is **reshoring**, which is the process of returning the production and manufacturing that had been offshored abroad back to the U.S. After peaking in the early 2000s, U.S. industrial electricity consumption has been a smaller share of total retail electricity sales in recent decades, but recent policy and market shifts are contributing to a renewed wave of domestic manufacturing investment. The return of industry to the U.S. could contribute to increased electricity demand over time.

A major source of current and near-term load growth is the **acceleration and expansion of data centers**, driven by the rapid increase in streaming, cloud computing, digitalization, and AI. A recent study from the Electric Power Research Institute (EPRI) finds that data centers could grow to consume 9-17% of U.S. electricity demand by 2030, increasing from 4-5% today.[55] The same analysis estimates that total nominal U.S. data center capacity in 2024 is between 35 GW and 44 GW, with the potential to reach 56 GW to 132 GW by 2030, depending on a low, medium, or high growth scenario. Peak load is estimated to be about 21 GW to 22 GW in 2024 and projected to grow to 45 GW to 94 GW by 2030. The peak is lower than nominal capacity due to utilization factors and a lag as new data centers ramp up operations.[56] Overall, total data center consumption is estimated to be about 177 TWh to 192 TWh in 2024 and could grow to 380 TWh to 790 TWh by 2030.[57]

Figure 16: *Nominal Capacity and Peak Load Projections from EPRI*



Source: Electric Power Research Institute (EPRI), Powering Intelligence 2026: Updated Scenarios of U.S. Data Center Electricity Use and Power Strategies, February 2026, https://www.epri.com/research/products/000000003002034696.

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[52] Pieter Gagnon, An Pham, Wesley Cole, and Anne Hamilton, *2024 Standard Scenarios Report: A U.S. Electricity Sector Outlook*, December 2024, https://www.osti.gov/servlets/purl/2496240

[53] It's worth noting that this trajectory assumes the Inflation Reduction Act tax credits and incentives expire at the original end date.

[54] Pieter Gagnon, An Pham, Wesley Cole, and Anne Hamilton, *2024 Standard Scenarios Report: A U.S. Electricity Sector Outlook*, December 2024, https://www.osti.gov/servlets/purl/2496240

[55] Electric Power Research Institute (EPRI), *Powering Intelligence 2026: Updated Scenarios of U.S. Data Center Electricity Use and Power Strategies*, February 2026, https://www.epri.com/research/products/000000003002034696

[56] Ibid.

[57] Ibid.

Crucially, data center load growth is often concentrated in specific geographies or hotspot regions. Today, many data centers are concentrated in Virginia (PJM) and Texas (ERCOT), but growth is expected in additional states as developers expand their operations and diversify. Today, only Virginia has data centers consuming over 20% of total electricity, but EPRI reports that by 2030, data centers may exceed 20% of demand in Oregon, Iowa, Nebraska, Nevada, Wyoming, Arizona as well. By 2030, Virginia's share of load attributed to data centers could increase from >20% to 39-59%.[58] Other states with projected data center load growth include New Mexico, Ohio, Pennsylvania, Indiana, Louisiana, and Mississippi.

Because much of the data center load growth is concentrated in specific regions, this can lead to local infrastructure constraints on the distribution system. High concentration of new load can overwhelm substations, transformers, and feeder circuits, forcing upgrades. The scale and pace of new load and generation are also intensifying interconnection bottlenecks, which can delay new resources coming online, large customers connecting to the grid, and the grid upgrades required to connect them.

Concentrated load additions in a particular zone can also drive heavier regional transfers and overload transmission paths, triggering the need for reinforcements. NERC highlights PJM as a clear example: beginning in 2023, PJM identified "large load increases in specific areas" driven primarily by new data centers and incorporated them into its planning models; NERC notes these increases are "driving heavier, increased regional transfers and the consequent need for significant system reinforcement." NERC further notes that PJM observed large changes in transmission interface flows associated with load growth in the Dominion zone and eastern PJM, approximately 10 GW (2029) and 15 GW (2032) increase between load forecasts used in PJM's 2022 and 2024 planning cycles, attributed primarily to data centers, electrification, and EV adoption.

At the same time, transmission expansion is not motivated by data centers alone, as discussed in the sections above. NERC reports that new transmission projects are being driven by reliability needs broadly defined, including replacing aging infrastructure, integrating renewable generation, accommodating retirements, and meeting higher load forecasts.[59] DOE similarly finds a "pressing need" for additional transmission and highlights that increasing interregional transfer capability can deliver the largest benefits, including bringing cost-effective generation to high-priced load areas and reducing congestion.[60]

In addition to accelerating demand, the power sector is confronting several compounding pressures, including more frequent and severe extreme weather, supply-chain constraints for critical equipment, heightened affordability concerns, and evolving policy and regulatory requirements. Taken together, these dynamics create a "perfect storm" of converging challenges for the electric system.

Near-Term Rate Impacts

Retail electricity rates have been rising in many parts of the country, and customers are feeling the impact on their monthly bills. Recent analysis from LBNL finds that U.S. average retail electricity prices have been increasing faster than inflation since 2021, and that multiple underlying cost categories have been rising over the 2019–2023 period (with distribution capital spending a particularly important driver).[61] At the same time, **it is hard to attribute any given rate increase to a single factor: fuel and purchased power costs, capital investment needs, extreme weather and resilience spending, and regulatory decisions can all move rates**.

Emerging load growth, especially from large loads and data centers, can put upward pressure on rates when it requires new investment in generation, transmission, and distribution. In fast-growth regions, utilities are already planning major system expansions to maintain reliability. For example, Dominion Energy Virginia has highlighted customer growth and grid upgrade needs in filings and public communications, and in 2025 proposed its first base rate increase since 1992, citing rising costs and grid upgrades needed to reliably serve growth. Dominion's 2024 integrated resource planning efforts also reflect the scale of capacity additions under

[58] Ibid.

[59] North American Electric Reliability Corporation (NERC), *2023 Long-Term Reliability Assessment*, December 2023, http://nerc.com/globalassets/programs/rapa/ra/nerc_ltra_2023.pdf

[60] U.S. Department of Energy, Office of Electricity, *National Transmission Needs Study*, December 2023, https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf

[61] Lawrence Berkeley National Laboratory, *Retail Electricity Price and Cost Trends: 2024 Update*, December 2024, https://eta-publications.lbl.gov/sites/default/files/2025-01/retail_price_and_cost_trends_2024_update_final_v3.pdf

consideration to meet growing demand through the 2030s.[62] At the bulk-system level, NERC has similarly emphasized that rapidly changing load forecasts, especially in certain regions, are driving transmission reinforcement needs and increasing planning complexity.

Cost allocation (i.e., who pays) is one of the largest determinants of whether new large loads put upward pressure on rates for everyone else. In utility ratemaking, new infrastructure costs can either be directly assigned to the customer that drives the need (e.g., dedicated facilities or interconnection upgrades) or socialized across a broader customer class through general rates. When costs are closely assigned to the load that causes them, the risk of cost shifting to other customers is lower; when costs are broadly socialized, the potential for distributional impacts across customer classes increases. DOE's review of evolving large-load rate designs highlights this core issue explicitly: fair cost allocation and avoiding "unfair shifting of costs to other customers" is a central objective of emerging large-load tariff approaches.[63]

A related concern is stranded or abandoned cost risk, which is the risk that utilities build infrastructure to serve a large load that is delayed, scales down, or fully departs before the utility has recovered the investment to serve it. Because grid assets are financed and repaid over decades, a mismatch between asset life and customer commitment can leave remaining customers responsible for underutilized ("overbuilt") infrastructure if protections are not in place. DOE flags the mitigation of stranded-asset risk from underutilized investments as a key issue in large-load rate design.[64]

However, load growth can also create downward pressure on average rates in certain circumstances. Because many utility costs are fixed (or only weakly tied to kWh sales in the short run), higher sales can spread those fixed costs over more kilowatt-hours, lowering the average $/kWh and improving the utilization of embedded costs, if the system has headroom and the load is stable (i.e., there is not an unexpected load departure).[65] As highlighted in an earlier section, LBNL's recent analysis found that states with the largest increases in customer load in the last 5 years often experienced declines in inflation-adjusted average retailed electricity prices. However, the same study highlights that the relationship between load growth and rates is not uniform across states or customer classes, reinforcing that outcomes depend on system conditions and rate structures.[66]

Cyclical Nature of Growth

Periods of rapid electricity demand growth have often accompanied broader waves of industrial expansion, manufacturing investment, and technological change. In the United States, utilities have repeatedly faced moments when new industries or economic booms created pressure to build generation, transmission, and distribution infrastructure quickly, followed by periods of slower growth in which the system had time to absorb that investment. More recently, the U.S. experienced nearly two decades of relatively flat electricity demand before forecasts turned upward again, with much of the new growth tied to the commercial sector, including data centers, and the industrial sector, including manufacturing.[67, 68] That pattern is consistent with a broader historical lesson: surges in demand and investment are rarely linear, and periods of strong expansion are often followed by normalization, slower absorption, or changed market expectations.[69]

The current wave of AI-driven data center development may prove durable, but it still presents the same planning challenge utilities have faced in past boom periods: infrastructure decisions must be made before the full

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[62] Dominion Energy, "Dominion Energy Virginia Proposes New Rates to Continue Delivering Reliable Service and Increasingly Clean Energy," *Dominion Energy Newsroom*, 2025, https://news.dominionenergy.com/press-releases/press-releases/2025/Dominion-Energy-Virginia-proposes-new-rates-to-continue-delivering-reliable-service-and-increasingly-clean-energy/default.aspx

[63] U.S. Department of Energy, Office of Policy, "Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities," January 2025, https://www.energy.gov/policy/articles/electricity-rate-designs-large-loads-evolving-practices-and-opportunities

[64] Ibid.

[65] Energy and Environmental Economics, Inc. (E3), *Ratepayer Impact Study*, December 2025, https://www.ethree.com/wp-content/uploads/2025/12/RatepayerStudy.pdf

[66] Lawrence Berkeley National Laboratory, *Retail Electricity Price and Cost Trends: 2024 Update*, December 2024, https://eta-publications.lbl.gov/sites/default/files/2025-01/retail_price_and_cost_trends_2024_update_final_v3.pdf

[67] U.S. Energy Information Administration, "After More Than a Decade of Little Change, U.S. Electricity Consumption Is Rising Again," *Today in Energy*, May 13, 2025, https://www.eia.gov/todayinenergy/detail.php?id=65264

[68] U.S. Energy Information Administration, *Electric Power Annual*, https://www.eia.gov/electricity/annual/

[69] Arman Shehabi, Alex Newkirk, Sarah J. Smith, et al., *2024 United States Data Center Energy Usage Report*, December 20, 2024, https://escholarship.org/uc/item/32d6m0d1

trajectory of demand is known. Other markets have shown how optimistic expectations can accelerate investment during an upswing and then leave participants exposed when conditions change; for example, the pronounced housing boom and bust in the 2000s,[70] and a study by the National Bureau of Economic Research (NBER) finds that large market booms are associated with higher subsequent volatility even when they do not always end in a crash.[71]

Against that backdrop, the utilities and regulators are exploring large-load tariffs and ratepayer protection mechanisms. These protections are not to prevent data center growth, but to reduce the risk of resulting stranded or underutilized costs being shifted to other customer classes if the new and fast-growing projected load does not fully materialize.

The Importance of Ratepayer Protections

Ratepayer protections are increasingly important because traditional utility planning and tariffs were built around incremental, diversified load growth, that is, the assumption that demand changes gradually across many customers and that investments can be recovered broadly over time. By contrast, modern large loads can introduce customer-specific risks: a single project may require substantial upgrades; timelines can shift; and a facility can scale, curtail, or exit in ways that leave costly infrastructure underutilized. Without guardrails, those costs and risks can be shifted to other customers through general rates, even if the upgrades primarily served one load. As a result, regulators and utilities are developing large-load specific tariffs, that include provisions such as direct assignment of upgrade costs, exit fees, minimum demand commitments, collateral requirements, and long-term contracts to protect other ratepayers from cost shifts while ensuring the system is built and operated in a way that maintains reliability.

New Large Load Rate Design

Because traditional utility planning and tariffs have been constructed assuming incremental, diversified load growth, they did not include targeted protections that insulated smaller ratepayers from rate increases stemming from risks such as declining load growth, lower-than-expected utilization, or overbuilding. With the understanding that the introduction of large loads may increase risks for remaining ratepayers, large load tariffs are designed to shift these risks to the large load sources themselves. Regulators and utilities are actively exploring different rate designs to minimize risks and cost-shifts to other ratepayers while still ensuring reliable energy for data centers, supporting state policy objectives, and enabling utilities to collect their revenue requirement.

Twenty-five utilities across 19 states have filed data center-specific tariffs, with the majority (18) filed or approved in 2024 and 2025 alone.[72] Because this is an emerging focus, large load tariff design continues to evolve. Several key components to protect ratepayers already feature across existing large load tariffs. Below is an overview:

Collateral requirements can be designed to reduce the likelihood of stranded costs from system upgrades being passed to other ratepayers. Collateral requirements enable utilities to confirm that large loads requesting interconnection can cover costs, from monthly bills to exit fees to penalty fees if they default on their contract. Collateral can take several forms, but common ones include: irrevocable letters of credit (ILOCs) from banks, which ensures cost-collection for the utilities, regardless of the ability of the large load to pay; cash deposits, which are usually determined by contracted load capacity; and guarantees from parent/affiliate companies with strong credit ratings. While the magnitude of the collateral requirement varies across tariffs, common values range from 12 to 25x the large load customer's largest monthly bill or minimum monthly charge (if applicable), with some tariffs deriving the value from contracted load capacity. In setting these requirements, utilities and regulators must exercise judgment to ensure that collateral is sufficient to protect other ratepayers without being excessive and unnecessarily deterring potentially beneficial new load. As an example of a tariff with collateral requirements, Evergy

[70] Craig Burnside, Martin Eichenbaum, and Sergio Rebelo, "Understanding Booms and Busts in Housing Markets," *Journal of Political Economy 124*, No 4, August 2016, https://doi.org/10.1086/686732

[71] Robin Greenwood, Andrei Shleifer, and Yang You, *Bubbles for Fama*, NBER Working Paper No. 23191, February 2017, https://www.nber.org/papers/w23191

[72] Latitude Media, "The Terms of Power: Inside the New Utility Rates for Data Centers," March 2026, https://www.latitudemedia.com/research/the-terms-of-power-inside-the-new-utility-rates-for-data-centers/

Missouri must provide collateral equal to two years of minimum monthly bills.[73]

Utilities also leverage **long-term energy contracts** to ensure a minimum horizon over which they can collect guaranteed revenues. Utilities already rely on long-term contracts for tariffs with non-data center customers, so this tariff component's efficacy has already been demonstrated. For instance, NV Energy's Clean Transition Tariff, which targets large customers with >5 MW of load, facilitates long-term energy supply agreements with clean energy suppliers of >15 years.[74] Similarly, Indiana Michigan Power's Industrial Power Tariff includes a 12-year minimum initial contract term after the load ramp period.[75] Finally, Portland General Electric's large Non-Residential Green Energy Affinity Rider requires a 5-to-20-year contract term.[76]

While cost shifts occurring across customer classes are a risk, non-data center customers can also be left paying more than their fair share if they are incorrectly assigned to the same customer class as the large load customers that are driving system upgrade costs. Defining customer classes in an accurate, sufficiently granular manner is key to ensuring all customers pay their fair share. To this end, incorporating a **minimum load requirement** into the definition of large load customer classes ensures a meaningful distinction between small commercial customers and true large loads. For instance, Indiana Michigan Power's Industrial Power Tariff is eligible only to customers whose minimum load is 70 MW if the customer has a single facility, or 150 MW in aggregate in the customer has multiple facilities.[77]

Because the scale of the peak demand of large load customers drives infrastructure investment costs, **minimum monthly demand charges** based off contracted, rather than empirical, load ensure utilities recover their fixed costs, even if large load customers end up demanding less power than their contracted capacity. Various mechanisms exist: the minimum charge can be defined based off one of: a percent of contracted capacity; a percent of the customer's historical peak demand; or a fixed floor determined by the utility. By implementing a minimum demand charge that was defined as the greater of a) 80% of contracted capacity or b) 80% of highest historical billing demand, for instance, Indiana Michigan Power minimized risk in their Industrial Power Tariff.[78]

To hedge against the risk of declining utilization, some utilities have turned to incorporating a **minimum load factor or PUE (Power Usage Effectiveness)** into their large load tariffs. This can include load shed requirements or demand response programs, wherein during times of high system demand, utilities can signal a need for customers, including large loads, to reduce their load temporarily.

Utilities have also used **exit fees** to discourage large load customers from leaving their contract before the contract end date, overestimating their capacity needs, or submitting speculative interconnection requests. In the instance that a large load customer does leave early, default, or reduce their capacity, these exit fees can help cover the costs of system upgrades that the utility has already incurred because of that customer. Exit fee structures vary but are often defined based on monthly charges. For example, AEP Ohio's Schedule Data Center Tariff allows a customer to terminate the contract early for a fee equal to 36 months of their minimum monthly charge.[79] Another component to exit fees is eligibility. In AEP Ohio's example, the termination clause only allows those customers whose contract has been in effect for at least 5 years and have given the utility 3 years of advance notice are eligible to exit.

The components summarized above are key considerations in the design of large-load tariffs intended to support data center interconnection while limiting the risk that large step increases in load impose costs on other ratepayers. When structured to align cost responsibility with the risks created by large new loads, such tariffs can help utilities and regulators manage system expansion in a way that reduces the potential for cost shifting across customer classes over the long term.

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[73] Missouri Public Service Commission, "PSC Approves Evergy Large Load Power Service Plan with Customer Protections," November 2025, https://psc.mo.gov/Electric/PSC_Approves_Evergy_Large_Load_Power_Service_Plan_with_Customer_Protections--pr-26-38

[74] Elaine Goodman, "Nevada Regulators Give Nod to NV Energy Clean Transition Tariff," *RTO Insider*, 2025, https://www.rtoinsider.com/100330-nevada-regulators-approve-nv-energy-clean-transition-tariff/

[75] Indiana Michigan Power Company. Tariff Submission, Cause No. 46097. Filed with the Indiana Utility Regulatory Commission, February 25, 2025.

[76] Portland General Electric, Large Nonresidential Green Energy Affinity Rider, Schedule 55, https://assets.ctfassets.net/416ywc1laqmd/Cisc2UrDoVmUBwV1fqVqb/9c31f3879d0ea2c907bac30929ce1e04/Sched_055.pdf

[77] Indiana Michigan Power Company. Tariff Submission, Cause No. 46097. Filed with the Indiana Utility Regulatory Commission, February 25, 2025.

[78] Indiana Michigan Power Company. Tariff Submission, Cause No. 46097. Filed with the Indiana Utility Regulatory Commission, February 25, 2025.

[79] AEP Ohio, "Data Center Tariff,"https://www.aepohio.com/company/about/rates/data-center-tariff/

CASE STUDY

Evaluating the System Impacts of a Hypothetical 100 MW Data Center

The large loads drawing the most attention today are AI-driven data centers, which are expanding rapidly across the country and contributing to significant load growth. To make the discussion around the impact of data centers on the grid more concrete, E3 evaluated a hypothetical 100 MW data center located in Dominion Energy Virginia's service territory.

This analysis illustrates:

- The types of infrastructure required to serve large loads
- The revenues generated under modern large-load tariffs
- The balance between costs and revenues under different scenarios
- The speed of cost recovery under different customer load profiles
- The effectiveness of ratepayer protection mechanisms in mitigating risk

Key Assumptions

The analysis considers a conservative case in which the hypothetical 100 MW data center drives incremental investment in both generation and transmission. That is, in this scenario it is assumed that there is no existing headroom on the system to accommodate the new large load and new investment is required.

Fixed and variable costs for new generation were derived from E3's internal RECOST model. For transmission, E3 assumed 1 mile of new facilities is required, at an illustrative cost of $10,000 per MW-mile. E3 also assumed a new natural gas pipeline would be needed to serve incremental generation, consisting of 5 miles of pipe at $50,000 per MW-mile. Note that if there was additional headroom on the system to accommodate the new data center, fewer investments in new generation and transmission infrastructure would be required, and total costs would be lower.

To estimate the revenues brought in by the data center, the analysis assumes the customer will be within Dominion's new proposed GS-5 rate class, eligible for non-residential customers with demand of 25 MW or more.[80] GS-5 includes minimum demand floor tied to the customers contracted demand, which is the primary mechanism of the tariff to reduce fixed cost recovery risk if the data center underutilizes the utility service; with large loads paying a minimum of 85% of distribution and transmission demand, and 60% of generation demand.[81] GS-5 also requires that large load customers provide $1.5 million per MW of contracted capacity in collateral to mitigate risk of underutilization or customer default. The tariff requires a minimum contract term of 14 years, which includes a 4-year ramp time.

For the purposes of this analysis, it is also assumed that GS-5 will contain several utility riders that the large customer would be responsible for. GS-5 riders have not yet been finalized, so E3 used the corresponding GS-4 riders as a proxy. Detailed GS-5 charge assumptions can be found in the Appendix.

[80] Virginia State Corporation Commission, "In Biennial Review Ruling, SCC Creates New Class for Large-Scale Energy Users," news release, 2025, https://www.scc.virginia.gov/about-the-scc/newsreleases/release/scc-issues-order-on-dev-biennial-review-2025/scc-rules-in-dev-biennial-review-case.html

[81] Timothy P. Stuller, witness testimony, Virginia State Corporation Commission, Case No. PUR-2023-00170, 2025, https://www.scc.virginia.gov/docketsearch/DOCS/84s%2301!.PDF

Micro Perspective: Cost Responsibility and System Contributions

At the project level, a key question is whether an individual data center, once operational, pays the full cost required to serve it. More specifically, if a new large load requires incremental investment in generation, transmission, and related infrastructure, does the customer generate sufficient revenues under the applicable tariff to cover those costs, or potentially even contribute more than its cost of service?

Base Case: Cost vs. Revenues

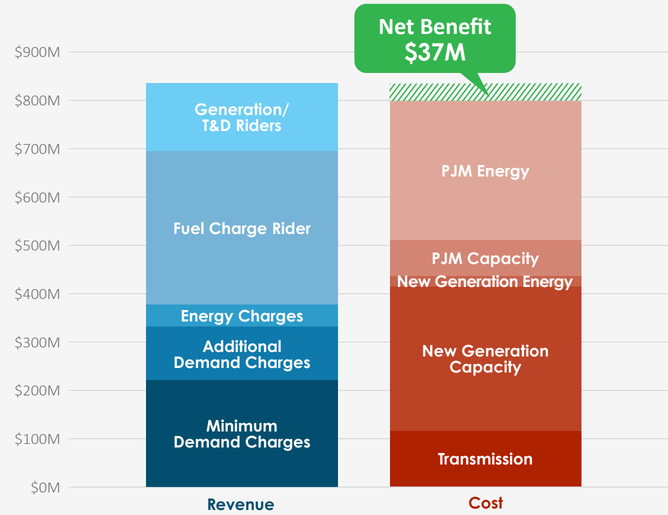
E3 found that, for a hypothetical 100 MW data center in Virginia, the utility revenues collected from the customer are broadly comparable to the incremental cost to serve the load on a lifetime net present value (NPV) basis. However, the balance between costs and revenues is sensitive to assumptions, particularly the resource mix used to serve the additional demand.

Figure 17 illustrates an example resource mix, referred to as the "Base Case" in this analysis, and informed by the most recent Dominion IRP: 10% utility-scale photovoltaic (PV), 10% gas combined-cycle, 10% onshore wind, 10% 4-hour lithium-ion battery, and 60% purchases from the PJM market. Under this resource mix, the total cost to serve the data center load is expected to be about $799M (NPV), while total revenues collected from the data center are estimated at approximately $836M (NPV), yielding an estimated net benefit of roughly $37M (NPV), or $0.000027 per kWh.[82]

This net system benefit indicates the data center is paying more into the system than the cost that it took to bring the facility online. Major cost components include investments in new generation capacity and energy (~$322M), new interregional transmission (~$114M), and purchases from the PJM market (~363M). On the revenue side, the largest components are demand-related charges (~$236M, including $219M attributable to minimum demand requirements), energy charges (~$44M), and utility riders ($456M), such as fuel, generation, and transmission and distribution riders.

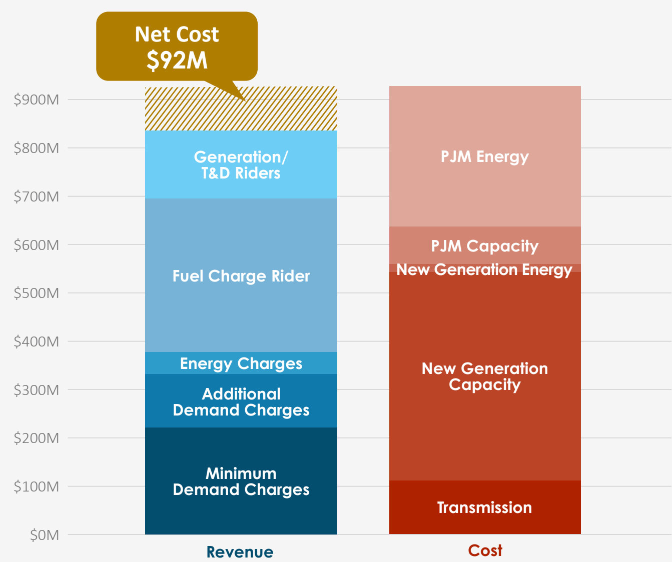
As noted above, the cost and revenue results are highly sensitive to the underlying assumptions, especially the cost of the resource mix used to serve incremental load.

Figure 17: *Utility Costs vs. Revenues for Hypothetical 100 MW Data Center – Base Case (NPV 2025$)*



This dynamic is reflected in the sensitivity case shown in Figure 18 below: higher cost resource mixes can shift the net result for the data center from a system benefit to a net system cost.

Figure 18: *Utility Costs vs. Revenues for 100 MW Hypothetical Data Center – Sensitivity: Higher Cost Resources (NPV 2025$)*



[82] Assuming 100.2 million MWh of electricity delivered, consistent with 2025 sales

By contrast, with lower cost resources, the total system cost declines while the data center's revenue contribution (under the same assumed Dominion GS-5 tariff) remains unchanged, resulting in a larger net benefit to the system (Figure 19).

***Figure 19:** Utility Costs vs. Revenues for 100 MW Hypothetical Data Center – Sensitivity: Lower Cost Resources (NPV 2025$)*

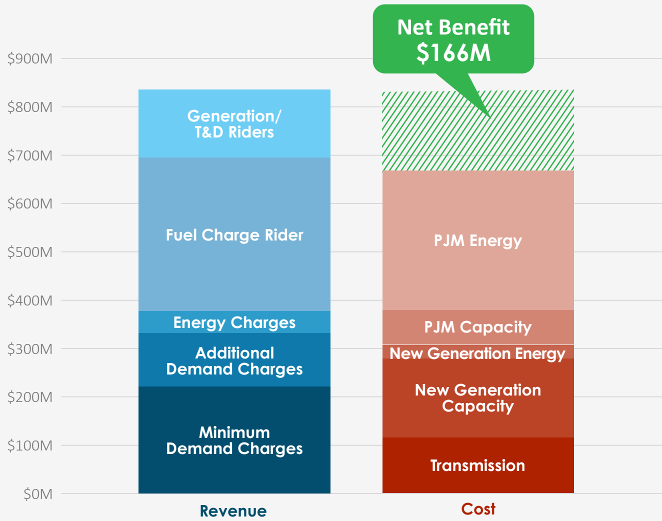
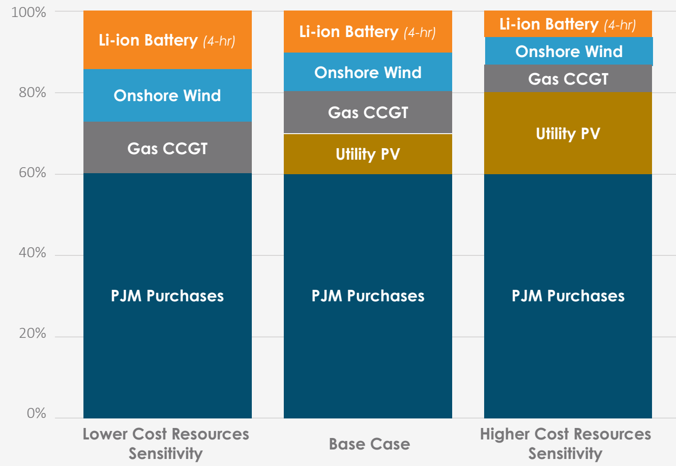


Figure 20 illustrates how the estimated net system impact varies across several example resource mixes, the Base Case and the two sensitivities: lower-resource cost mix and higher-resource cost mix. These cases are not intended to represent the full range of possible portfolios; they are included as an illustrative comparison of relatively lower-cost versus higher-cost resource mix outcomes under the modeling assumptions. In the first two columns, the hypothetical data center brings net benefits to the system, indicating the revenue that it contributes outweighs the cost to bring it online. In the final column, the data center brings net costs to the system, meaning the revenue it pays is not sufficient to cover the investment costs needed to support the data center's new large load. However, this does not take into account that other customers are still likely to benefit from the system upgrades made to accommodate the data center, such as the additional transmission lines.

***Figure 20:** Utility Cost vs. Revenue Scenario Summary (NPV 2025$)*



	Lower Cost Resources Sensitivity	Base Case	Higher Cost Resources Sensitivity
Total Cost	$670M	$799M	$927M
Total Revenue	$836M	$836M	$836M
Net System Impact	-$166M	-$37M	+$92M

The examples above reflect a relatively conservative view of the costs required to serve a new 100 MW data center, assuming the load drives incremental investment in capacity and other infrastructure. In some jurisdictions, however, the system may have sufficient existing headroom to serve additional load without requiring near-term generation or transmission buildout. In a more optimistic scenario where the data center can be accommodated largely within existing capacity, the cost to serve the data center would likely be significantly lower, and incremental revenue from the new customer could help spread the embedded fixed costs of existing assets over more kilowatt-hours. The new customer would still be expected to cover any incremental variable costs (such as energy and fuel-related charges) and any local distribution upgrades required to connect and serve the facility. Under these conditions, average retail rates could face downward pressure because largely fixed system costs would be recovered across a larger number of electricity sales.

Payback Period and Cost Recovery

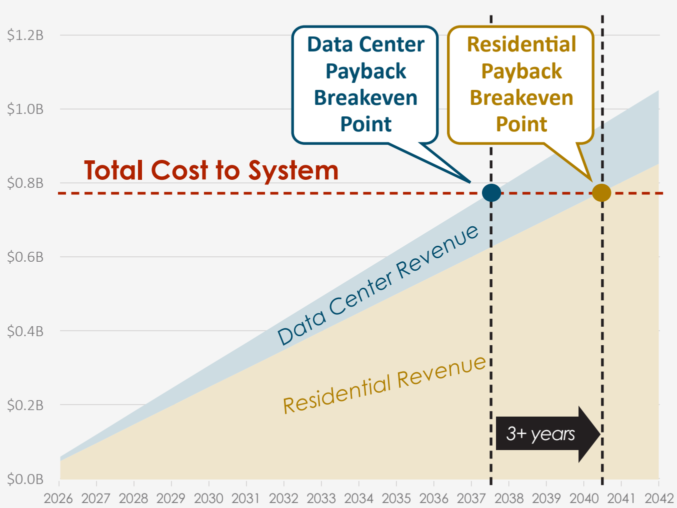
Beyond whether revenues exceed modeled cost of service on an NPV basis, high load factor customers can also improve the speed and certainty of utility cost recovery.

Because data centers consume electricity at a steady, near-continuous rate, they generate a higher and more predictable revenue stream per unit of capacity than lower load factor customers. This means that, for a given level of infrastructure investment, the contribution margin associated with serving a data center can accelerate the payback period relative to a lower load factor customer class.

To illustrate this dynamic, E3 compared recovery of the same 100 MW capacity investment under two different revenue profiles: one associated with a data center and one associated with an equivalent amount of residential load. Under the data center case, the utility recovers the investment in approximately 13 years. Under residential revenue assumptions, the same investment takes roughly three additional years to recover (Figure 21).

This faster recovery period can reduce financial risk for utilities by improving the timing and certainty of revenue collection. In turn, it can reduce the likelihood that cost recovery is deferred or that unrecovered fixed costs place upward pressure on other customers over time. It's worth noting that this is a conservative case that assumes fast ramp-up for residential loads. If that ramp were to be slower, then the payback period would similarly extend.

Figure 21: *Investment Cost Recovery for 100 MW Capacity under Data Center vs. Residential Revenue Streams (2025$)*



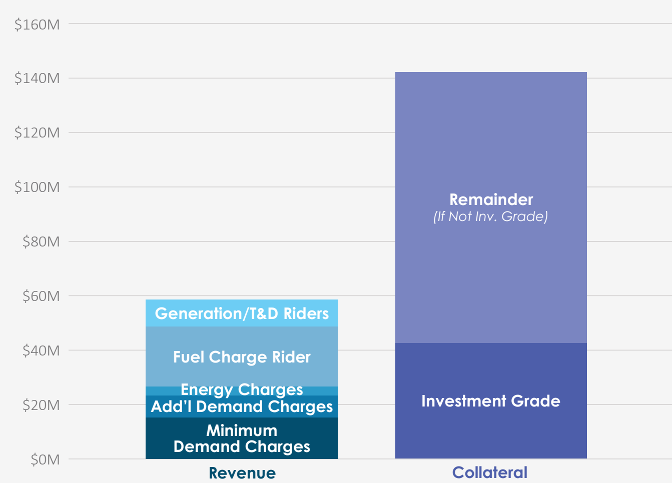
Taken together, the results above suggest that, from a micro perspective, a large high load factor customer can do more than simply cover its incremental cost of service. Under appropriate tariff design and supply conditions, it can also improve utilization of existing or newly built infrastructure and accelerate recovery of utility investments.

Non-Payment Risk

The analysis also examines how GS-5 collateral requirements mitigate non-payment risk for an individual data center. Under the proposed tariff, large-load customers must provide collateral equal to $1.5 million per MW of contracted capacity, subject to credit provisions. This scenario is not intended to represent full load departure, but rather a delay or initial failure in payment.

Figure 22 compares the anticipated revenue generated from a new 100 MW data center with the level of collateral required under the GS-5 tariff. The results show that, in the case of non-payment or delayed payment, required collateral from an investment-grade customer would cover most of the expected first-year revenues, while collateral requirements for non-investment-grade customers could exceed those anticipated revenues.

Figure 22: *First-Year Anticipated Revenue vs. Required Collateral for Hypothetical Data Center (2025$)*



This is an important distinction from the Base Case cost vs. revenue analysis above. Collateral is not intended to represent ongoing tariff revenue collected during normal operations. Rather, it functions as a financial safeguard against early-stage non-payment, helping protect the utility and other customers from near-term exposure.

Macro Perspective: Managing System Risk from Load Uncertainty

At the system level, the primary concern is not only whether an operational data center pays its cost of service, but whether utilities may build generation, transmission, or related infrastructure in anticipation of large new load that is later delayed, reduced, or never materializes. In such cases, the system could be left with underutilized or unused assets, raising the possibility that associated costs would be shifted to other customers.

To address this concern, utilities and regulators are increasingly incorporating ratepayer protection provisions into large-load tariffs. Dominion's proposed GS-5 tariff includes many such mechanisms, including exit fees, minimum demand charges, collateral requirements, and long-term contractual commitments. These provisions are intended to reduce the risk that investments made to serve large loads become unrecovered if the customer fails to materialize or underutilizes service.

Worst-Case Load Departure Scenario

The analysis next evaluates an extreme "worst-case" scenario in which the data center load never materializes, using the same hypothetical 100 MW data center under Dominion Energy's GS-5 tariff.

Historically, the risk of large industrial load departure was largely borne by the broader rate base, with some limited protections such as minimum bills or negotiated contracts. In contrast, modern large-load tariff structures are designed to mitigate these risks through provisions such as exit fees, minimum demand charges, collateral requirements, and contractual obligations. These mechanisms help ensure that, even in cases of load departure, the cost exposure to other customers is limited and aligned with the risks created by new large loads.

As shown in Figure 22, in the case of non-payment or delayed payment, the customer's collateral would be drawn upon and would cover most of the expected first-year revenues. If non-payment persists, however, the utility could face stranded asset risk. In practice, there are several mechanisms available to mitigate this outcome before reaching a worst-case scenario:

+ **Capacity reassignment:** The departing customer may identify a replacement customer to assume the associated capacity and financial obligations, which can reduce or eliminate exit fees.
+ **Notice period:** Customers may reduce their contracted capacity by up to 20% at no cost, or by up to 50% if a replacement customer is secured, provided they give 36 months' notice.

If non-payment continues and these options are not exercised, the remaining risk is addressed through contractual protections. Under GS-5, the customer is responsible for a substantial exit fee, structured as minimum demand charges covering a 14-year contract period, payable upfront. This obligation is in addition to any collateral already posted.

Under the worst-case scenario of full load departure, the GS-5 tariff substantially improves cost recovery under a stranded asset situation and limits impacts to other rate payers. Modeled results suggest that these protections can reduce the net system cost by 86% compared to previous tariff design (Figure 23).[83,84]

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[83] In practice, the capacity built for a data center that never comes online would likely be repurposed rather than fully abandoned, leading to additional revenue generated for the utility. The results shown in Figure 24 therefore represent the absolute worst-case scenario.

[84] The assumed resource mix is the same as in the Base Case: 10% utility-scale solar PV, 10% gas combined-cycle, 10% onshore wind, 10% 4-hour lithium-ion battery storage, and 60% purchases from the PJM market.

The analysis assumes total system investment of approximately $415M to serve the load. Under the previous large-load tariff designs, a data center that never comes online would generate little to no revenue, leaving the investment largely unrecovered. Under GS-5, by contrast, the exit fee alone could generate $215M in revenue, even if the facility never takes service.[85] This is in addition to the collateral, which could amount to approximately $142M depending on customer credit quality.

As a result, total revenue recovery under GS-5 is estimated at approximately $357M, compared to $415M in total costs, leading to $57M in net system costs (Figure 23). This represents an 86% decrease in net costs for the system compared to previous tariff design. Even in this worst-case scenario, the resulting net cost would have a minimal impact on individual customers, increasing average retail rates by approximately $0.000042 per kWh on average.[86]

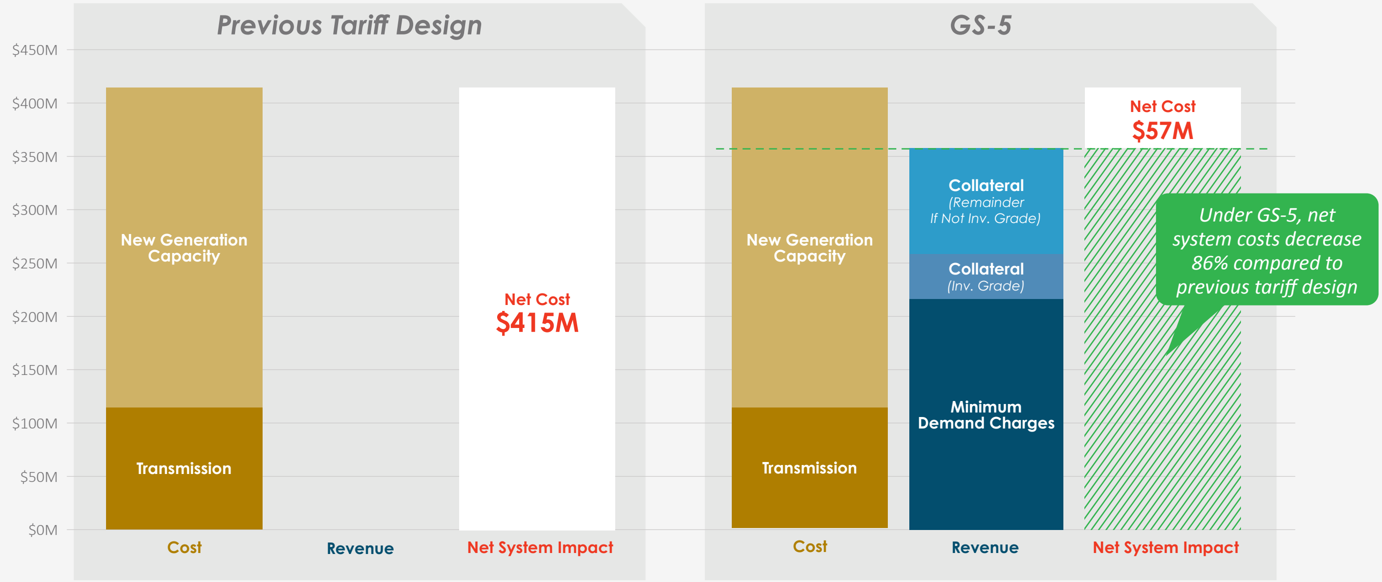
These results demonstrate how robust tariff design can materially reduce the risk that other ratepayers bear the costs of investments made to serve large new loads. Many of the protections embedded in GS-5 are relatively new and unprecedented; historically, the costs associated with large load departure were more often borne by the broader rate base. As similar tariff structures continue to evolve across jurisdictions, the extent of these protections may vary.

It is also important to note that this scenario represents an extreme and unlikely outcome in which the anticipated load never materializes. In practice, the capacity built to serve the project would likely retain value, either by serving another large customer or by being sold into the PJM capacity market, thereby generating additional revenue.

Additionally, this scenario assumes no existing system headroom and includes relatively high-cost resources in the resource mix. If lower-cost resources are available, net system benefits could be even higher in the event of full load departure, as GS-5 still enables substantial revenue recovery from the large-load customer.

Overall, these results suggest that, from a macro perspective, the principal system risk associated with large-load uncertainty is highly sensitive to tariff design. Modern protections such as exit fees, minimum demand charges, collateral requirements, and contractual safeguards can materially reduce the exposure of other customers to stranded or under-recovered costs.

Figure 23: *Revenues vs. Costs for Hypothetical 100 MW Data Center under Complete Load Departure (NPV 2025$)*[87]



85 The exit fee would be payable upfront, not over time.

86 Assuming 100.2 million MWh of electricity delivered, consistent with 2025 sales

87 There was the option for collateral under the previous rate design, but it was not mandatory like it is under GS-5.

Broader System Impacts

Beyond retail rate impacts, new large loads may catalyze broader investments in energy infrastructure with impacts that extend beyond what is required to serve the incremental load. As discussed above, the grid faces urgent needs for upgrades and modernization, such as replacing aging assets and expanding interregional transmission to deliver generation to high-load centers and reduce congestion. In some cases, data centers can accelerate these upgrades and may fund a portion of them directly through dedicated infrastructure payments or tariff structures.

While these investments may be initiated to serve large loads, they can provide broader system-wide benefits by improving reliability, supporting grid modernization, and enhancing overall system performance for other customers. At the same time, rapid load growth can also increase near-term system needs and place upward pressure on infrastructure development timelines, particularly in regions already facing capacity constraints.[88]

This dynamic also extends to resource development. Data centers are major purchasers of electricity and, in some cases, have supported the expansion of renewable energy and emerging technologies such as advanced geothermal and long-duration storage.[89,90] However, in some regions, the pace and scale of new load has also contributed to continued reliance on existing fossil generation or the development of new natural gas capacity to maintain reliability. As a result, the net impact of large loads on the resource mix and emissions trajectory depends on how they are integrated into system planning, procurement strategies, and regulatory frameworks.

Implications for Retail Rates

The extent to which modeled net system costs or benefits ultimately affect retail rates depends on cost allocation and rate design.

Even if a large data center creates net system costs, or, alternatively, net system benefits, the resulting rate effects will vary depending on how those costs and benefits are assigned in the utility's cost-of-service and rate design framework. In particular, the retail rate implications will depend on how each cost component is treated, how the costs are allocated across rate classes based on demand, energy, and customer counts; and whether any revenues from the large load are credited broadly across the system or primarily to the class serving the load.

For that reason, the modeled system impacts presented in this case study should not be interpreted as translating mechanically into a specific rate effect for any particular customer class. Rather, they illustrate the underlying economics of serving a large new load and the degree to which modern tariff design can influence both project-level cost responsibility and broader system risk.

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88 Energy and Environmental Economics, Inc. (E3), *Ratepayer Impact Study*, December 2025, https://www.ethree.com/wp-content/uploads/2025/12/RatepayerStudy.pdf

89 BloombergNEF, "Power-Hungry Data Centers Are Driving Green Energy Demand," August 2025, https://about.bnef.com/insights/clean-energy/power-hungry-data-centers-are-driving-green-energy-demand/

90 S&P Global, "Data Centers Drive Surge in Clean Energy Procurement in 2024," *S&P Global Commodity Insights*, February 28, 2025, https://www.spglobal.com/energy/en/news-research/blog/energy-transition/022825-data-centers-drive-surge-in-clean-energy-procurement-in-2024

Additional Considerations

PJM Capacity Market

There are several additional factors that shape how data centers affect the electric system and retail prices that are outside the primary scope of this paper. In particular, this analysis does not evaluate broader wholesale market impacts, such as how rapid load growth influences capacity market outcomes or regional price formation. One issue that has received significant attention, though it is not the focus of this paper, is the impact of rapid data center load growth on PJM's capacity market and the extent to which higher capacity costs are ultimately reflected in retail rates for customers served by utilities that procure capacity through PJM. PJM has experienced sharp capacity price increases in recent auctions, and PJM's independent market monitor has concluded that data center load growth is a primary driver of recent and expected capacity market conditions, including tighter supply-demand balances and higher prices.

Recent reporting based on the market monitor's analysis also estimates that data center-related load forecasts represented a substantial share of capacity costs in PJM's latest auction, about $6.5 billion (roughly 40%) of the $16.4 billion total, highlighting how quickly these loads can influence market procurement requirements.[91] Data centers are not the only factor behind elevated auction outcomes (other drivers include retirements, market conditions, and deliverability constraints), but PJM's market monitor indicates they are a meaningful contributing factor in recent pricing dynamics.

While these macro-level dynamics are important, they involve system-wide market design, resource adequacy, and cost allocation considerations that extend beyond the primarily project-level (micro) focus of this report. These issues are explored in more detail in E3's prior work for the Virginia JLARC study.[92] As discussed there, potential approaches to addressing these impacts, such as allocating a greater share of system costs to large loads, may be conceptually straightforward but involve important tradeoffs and implementation complexities.

Data Center Size

The analysis above evaluates a hypothetical 100 MW data center, but some emerging campuses are expected to be much larger, on the order of 1 GW or more. While certain infrastructure needs may scale roughly with size, a campus at the 1 GW scale can introduce additional system impacts and planning considerations that are not simply proportional to a 100 MW project.

While the analysis included above conservatively assumes that the system will have no additional headroom to absorb a new 100 MW data center, in reality, some jurisdictions may have sufficient existing headroom to serve the load with limited incremental investment, depending on local transmission and distribution conditions. By contrast, a 1 GW campus is far more likely to drive major regional transmission upgrades and to materially affect a utility or ISO's load forecast and resource adequacy requirements. These projects also face greater exposure to long lead times for equipment, siting, and construction. At the same time, the risk of stranded or underutilized assets, and the associated load-departure risk, tends to be higher simply because the scale of the required infrastructure is larger.

Although very large campuses can therefore have larger grid impacts, the emerging ratepayer protection mechanisms embedded in large-load tariffs are intended to ensure that these costs and risks are appropriately assigned and do not unduly shift to other customers.

[91] Ethan Howland, "Data Centers Were 40% of PJM Capacity Costs in Last Auction: Market Monitor," *Utility Dive*, January 7, 2026, https://www.utilitydive.com/news/data-centers-pjm-capacity-auction/808951/

[92] Joint Legislative Audit and Review Commission (JLARC), *Virginia Data Center Study* (Richmond, VA: JLARC, December 9, 2024), https://jlarc.virginia.gov/pdfs/presentations/JLARC%20Virginia%20Data%20Center%20Study_FINAL_12-09-2024.pdf

The Other Option: Fully Islanded Facilities

The above sections describe the implications and potential effects of data centers connecting to the broader grid. However, that is not the only option available. Data centers and other large loads could operate fully independently from the electric grid, using their own on-site power resources to meet electricity needs. A fully islanded facility would not rely on the grid for normal operations, must balance its own supply and demand internally, and is responsible for providing its own generation and backup.

A data center may choose fully islanded service to accelerate speed to power, maintain greater control over reliability and operational continuity, and reduce exposure to grid interconnection delays, system constraints, or public opposition associated with new utility infrastructure. From the perspective of other utility customers, this approach may also present the lowest risk because it avoids placing new generation, transmission, or distribution investments into the utility rate base to serve that load. As a result, other ratepayers would generally be less exposed to retail rate increases or stranded-asset risk if the project is delayed, scaled back, or never fully materializes.

However, many data centers see this option as suboptimal because a fully off-grid facility must plan around its own peak demand and maintain its own reserves, as it cannot benefit from the resource sharing available on an interconnected system.

A small number of large North American facilities have chosen to operate outside the traditional grid, illustrating the tradeoff of fully islanded service: greater control over reliability and energization timing in exchange for taking on the responsibility to self-supply power. Historical examples are more common in remote industrial settings than in data centers, but they help show that large-load customers have at times pursued this model when grid service was unavailable, constrained, or impractical.

Historical examples of fully islanded large-load service in North America are more common in remote industrial settings than in conventional data centers, but they help illustrate why some large customers choose to self-supply power. One example is the Diavik Diamond Mine in Canada's Northwest Territories, a joint venture between Rio Tinto and Dominion Diamond Diavik.[93] Construction began in 2000, and the mine has been in operation since 2003 in an extremely remote area where extending grid infrastructure would be prohibitively costly. Diavik consumes roughly 200 GWh of electricity annually and historically operated as a fully islanded facility, with all power supplied by a 24 MW diesel plant until 2012. In that year, the site added four 2.3 MW wind turbines to partially serve load, with average wind penetration of about 7% and maximum instantaneous penetration reaching 52%. In 2024, the mine further supplemented its power supply with a 3.5 MW solar installation.[94] Therefore, Diavik provides a clear example of a large customer relying on dedicated on-site resources, rather than utility grid service, to meet continuous and large electricity needs.

A more recent example is Quanta Computer's Fremont, California manufacturing operation, which has been described as using a fully islanded microgrid to secure 24/7 power and avoid utility interconnection delays.[95] Together, these cases show that large customers may pursue islanded service either because grid access is impractical or because self-supply offers faster and more controllable access to power.

There are several tradeoffs to consider with a fully islanded option for bringing a data center online. Although this approach presents the lowest risk to other ratepayers, it also means the broader system does not benefit from any grid investments associated with serving the load or from the additional revenue the large customer could contribute. **Excluding large loads from the grid removes the opportunity for those customers to help fund system upgrades that may benefit all ratepayers.** Moreover, many of those grid investments need to be made regardless of new data center for reasons such as aging infrastructure, grid modernization, and reliability, as outlined in the chapters above. Under a fully islanded model, however, data centers would not be helping to pay for those upgrades. To the extent large loads can sometimes improve system utilization and help spread fixed costs over more sales, those potential benefits would also be foregone under a fully islanded model. In addition, a fully islanded facility reduces the role of state regulators and utilities in planning for and serving that load.

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[93] Natural Resources Canada, "Diavik Diamond Mine, Northwest Territories," accessed March 20, 2026, https://natural-resources.canada.ca/maps-tools-publications/publications/diavik-diamond-mine-northwest-territories

[94] Ibid.

[95] Bloom Energy, "Bloom Energy and Quanta Computer Forge Transformative Partnership to Power Silicon Valley's AI Revolution," *Business Wire*, April 29, 2024, https://www.businesswire.com/news/home/20240429880821/en/Bloom-Energy-and-Quanta-Computer-Forge-Transformative-Partnership-to-Power-Silicon-Valleys-AI-Revolution

Conclusions and Recommendations

Research and recent studies suggest that large load growth is arriving at a time when the electric system is already under significant investment pressure. As a result, concerns about retail rate impacts are understandable, but they should be evaluated in the context of broader cost drivers already affecting the grid, including aging infrastructure, modernization needs, transmission expansion, and reliability and resilience investments. While some tariff structures may not generate sufficient revenue and can leave existing infrastructure underutilized, large data center loads can, in some cases, reduce overall system pressures rather than increase them. As data center load grows, opportunities for data centers to provide these benefits may also increase.

The emergence of the data center sector as a force within the domestic energy landscape represents an opportunity for the modernization of the electric grid. This analysis demonstrates that the transition from traditional industrial loads to modern high-load-factor digital infrastructure can enable utilities to optimize historically underutilized assets. By maintaining a consistent demand profile, data centers serve as foundational anchor tenants that distribute fixed system costs across a significantly larger volume of sales. This can create downward pressure on per-unit electricity rates, suggesting that integrated data centers can serve as a potential financial engine to subsidize the broader health and resilience of the power system.

To institutionalize these benefits, it is recommended that commissions incorporate tariff design best practices, such as mandatory minimum demand charges and robust collateral requirements. These fiscal protections ensure that the capital-intensive nature of new infrastructure does not result in cost-shifting to residential or small-business ratepayers in the event of load departure or project delays. Furthermore, these principles should be codified into enforceable service agreements to provide long-term stability for both the utility and its customer base.

Utilities should prioritize the identification of existing grid headroom to strategically guide data center development toward regions with surplus capacity. The implementation of sophisticated power purchase agreement frameworks will allow these large-load customers to integrate private clean energy resources directly into the system. Such a strategy accelerates decarbonization objectives without requiring the utility to bear the full burden of new generation procurement costs. Data center developers are likewise encouraged to pursue full grid integration rather than isolated operations, as the infrastructure enhancements they fund provide essential energy security and hardened transmission assets for the entire community.

Ultimately, the alignment of private capital with rigorous regulatory oversight will determine the total public benefit of this industrial expansion. A collaborative approach to integrated transmission planning ensures that the rapid growth of AI and cloud computing infrastructure can act as a cornerstone for a more efficient and sustainable North American power system. By prioritizing operational transparency and precise cost allocation, stakeholders can transform this period of unprecedented load growth into an era of enhanced reliability and economic efficiency for all ratepayers.

Technical Appendix

Overview

This appendix provides additional detail on the assumptions and methodology used to evaluate the system impacts of new large loads, including treatment of tariff structures, load characteristics, and key modeling inputs.

The analysis is supported by an Excel-based model that is available for public use. The model allows users to vary key assumptions (e.g., load characteristics, resource mix, tariff design) and to evaluate the resulting impacts on system costs, revenues, and cost recovery. Instructions for use are provided within the model workbook.

GS-5 Overview

GS-5, Dominion's large load tariff, is designed for high-demand customers and includes provisions that allocate risk more directly to those customers. A central feature is the minimum demand requirement, which obligates customers to pay for at least 85% of their contracted demand regardless of actual usage, ensuring a stable baseline for cost recovery. The tariff also includes demand charges tied to peak usage, aligning revenues with system capacity needs. Customers are required to enter into long-term contracts, which help match infrastructure investment with expected load duration. In addition, GS-5 requires collateral or financial security sized to reflect potential exposure, providing protection in the event of non-performance. Exit fee provisions apply if a customer reduces load or terminates service early, allowing the utility to recover remaining infrastructure-related costs.

Modeling Framework

The analysis evaluates the costs and revenues associated with serving a hypothetical large load under a defined set of assumptions. Costs include generation, transmission, and associated infrastructure investments, as well as market purchases where applicable. Revenues are derived from the applicable tariff structure and underlying load shapes. To derive residential revenues, the analysis accounts for tiered volumetric rates, with different rates applied to the first 800 kWh of monthly consumption and to usage above that level. The analysis assumes typical monthly consumption of 1,000 kWh and therefore allocates approximately 80% of sales to the first tier and the remainder to the second tier.

All results are presented on a net present value (NPV) basis (2025$) over a 25-year analysis period to ensure consistency between cost and revenue streams. Where appropriate, select results are also presented on a first-year basis to provide additional context for specific tariff mechanisms.

Unless otherwise noted, the analysis assumes no available system headroom, such that new generation and transmission capacity are required to serve the modeled load.

Treatment of Tariff Riders

The modeled tariff structure is based on Dominion Energy Virginia's GS-5 framework, with rider values proxied using GS-4, as GS-5 values are not yet finalized.

To focus the analysis on revenues associated with serving incremental load, certain riders were excluded where they were not deemed to materially contribute to the cost of new capacity. These primarily include select environmental and policy-related riders (e.g., Regional Greenhouse Gas Initiative (RGGI) and Renewable Portfolio Standard (RPS) charges).

Treatment of Minimum Demand Charges, Collateral, and Load Departure

Minimum demand charges under GS-5 are modeled as a recurring revenue floor tied to contracted demand and are included in the revenue stream over the analysis period.

The analysis also considers a no-load scenario in which the anticipated large load does not materialize. Under GS-5, remaining minimum demand obligations are assumed to be satisfied on an accelerated basis. In the model, this is represented as an upfront payment equal to the net present value of 14 years of minimum demand charges, evaluated alongside collateral to assess stranded asset risk.

Collateral is treated as a one-time financial value associated with contracted capacity and discounted to present value (2025$). It is not included in the recurring revenue stream.

Technical Appendix

Load Shape Assumptions

The data center load is modeled as a high, steady demand profile, reflecting typical operating characteristics of large-scale computing facilities.

The residential load shape is derived from the National Laboratory of the Rockies (NRL) ResStock tool for Virginia and reflects typical patterns of residential electricity use, including daily and seasonal variability.

Resource Cost Assumptions

Resource cost assumptions used in this analysis are derived from E3's Resource Cost (RECOST) model. RECOST is E3's in-house discounted cash flow framework used to estimate the levelized cost of electricity (LCOE) and levelized fixed costs (LFC) for a range of generation and storage technologies, inclusive of capital, operating, and financing costs.

RECOST integrates market intelligence, E3 analysis, and publicly available data to develop cost estimates for new resource builds. The model assumes new builds are merchant-developed and incorporates assumptions related to capital expenditures, fixed and variable operations and maintenance costs, financing parameters, and policy impacts (e.g., tax credits and tariffs).