Pacific Northwest NATIONAL LABORATORY

PNNL-39627

Storing Affordability

Battery Storage as an Asset to Reduce Data Center Cost Shifts

June 2026

Devyn W Powell
Erik Anderson

U.S. DEPARTMENT of ENERGY

Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

PACIFIC NORTHWEST NATIONAL LABORATORY
operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
under Contract DE-AC05-76RL01830

Printed in the United States of America

Available to DOE and DOE contractors from
the Office of Scientific and Technical Information,
P.O. Box 62, Oak Ridge, TN 37831-0062
www.osti.gov
ph: (865) 576-8401
fox: (865) 576-5728
email: reports@osti.gov

Available to the public from the National Technical Information Service
5301 Shawnee Rd., Alexandria, VA 22312
ph: (800) 553-NTIS (6847)
or (703) 605-6000
email: info@ntis.gov
Online ordering: http://www.ntis.gov

PNNL-39627

Storing Affordability

Battery Storage as an Asset to Reduce Data Center Cost Shifts

June 2026

Devyn W Powell
Erik Anderson

Prepared for
the U.S. Department of Energy
under Contract DE-AC05-76RL01830

Pacific Northwest National Laboratory
Richland, Washington 99354

Abstract

This report examines how battery energy storage systems (BESS) can help utilities accommodate large load growth while protecting affordability for existing ratepayers. Rapid growth in electricity demand from artificial intelligence (AI) data centers is straining the U.S. grid. Furthermore, many new data centers are entering rural markets, which could offer economic benefits but may also pose implementation challenges for smaller utilities. At the same time, retail electricity prices are increasing faster than inflation, elevating customer affordability as a key challenge. While data centers have not been the primary driver of increases in residential prices to date, they have pushed wholesale energy and capacity prices higher in several markets. Fundamental utility cost-allocation principles show that data center growth can be rate-positive for existing customers only if new peak demand grows faster than the costs a utility must incur to serve it. Several factors, including a utility's degree of wholesale market exposure, forecast uncertainty and stranded-asset risk, and tariff design can determine the outcome of load growth on retail rates. Energy storage can make several affordability contributions in the face of this landscape of uncertainty and market volatility, including deferral of higher-cost grid investments through improved utilization of existing assets and flexibility of new large loads, insulation from volatile wholesale prices through peak shaving, and reliability support to address grid risks stemming from the behavior of AI data center loads. Different potential BESS deployment pathways—utility-scale front-of-the-meter systems, aggregated small-scale storage installations, and data center-sited behind-the-meter storage—are compared against each other and against conventional capacity alternatives. This framework is intended as a conceptual resource to utilities, particularly smaller public utilities with rural service territories, who may be considering the role that energy storage can play in insulating existing ratepayers from data center cost shifts.

Acknowledgments

This material is based upon work supported by the U.S. Department of Energy, Office of Electricity (OE), Energy Storage Division. The authors would also like to extend their thanks to Colin Hansen and Mike Shook at Kansas Power Pool for their input on the scoping of this report, as well as to Diane Baldwin and Alok Bharati Kumar for their invaluable contributions, support, and mentorship.

Acronyms and Abbreviations

AI	artificial intelligence
BESS	battery energy storage system
BTM	behind the meter
BYOC	bring your own capacity
C&I	commercial and industrial (customer classes)
Capex	capital expenditures
EIA	U.S. Energy Information Administration
FTM	front of the meter
kW/kWh	kilowatts/kilowatt-hours
LVRT	low-voltage ride through
MISO	Midcontinent Independent System Operator
MW/MWh	megawatts/megawatt-hours
PJM	PJM Interconnection
PUC	public utility commission
RTO	regional transmission operator
SPP	Southwest Power Pool

Contents

Figures

Tables

1.0 Introduction

The rapid acceleration in deployment of data centers built to meet artificial intelligence (AI)'s voracious appetite for computational power has forced a reckoning in the electricity sector, as utilities, regulators, and policymakers grapple with the question of how to serve these data centers' astronomical power demand without compromising the reliability of the grid or the affordability of electricity. Against a backdrop of increasing electricity rates, utilities and other grid stakeholders face growing urgency to identify solutions for interconnecting new loads without shifting costs to other ratepayers. While most research has indicated data centers have not been directly responsible for widespread residential rate increases to date, they have driven up wholesale prices in major markets and exacerbated supply chain challenges, risking the potential for more widespread future cost shifts (Monitoring Analytics, LLC 2026; Rochas 2026).

While effectively mitigating affordability risks associated with rapid and uncertain large load growth will require a constellation of solutions, battery energy storage systems (BESS) have emerged as a uniquely valuable tool. BESS can be deployed quickly, incrementally, and in many locations and configurations on the grid. Energy storage can also help utilities defer higher-cost investments, reduce exposure to volatility in wholesale power markets, and mitigate some grid reliability challenges associated with data center loads.

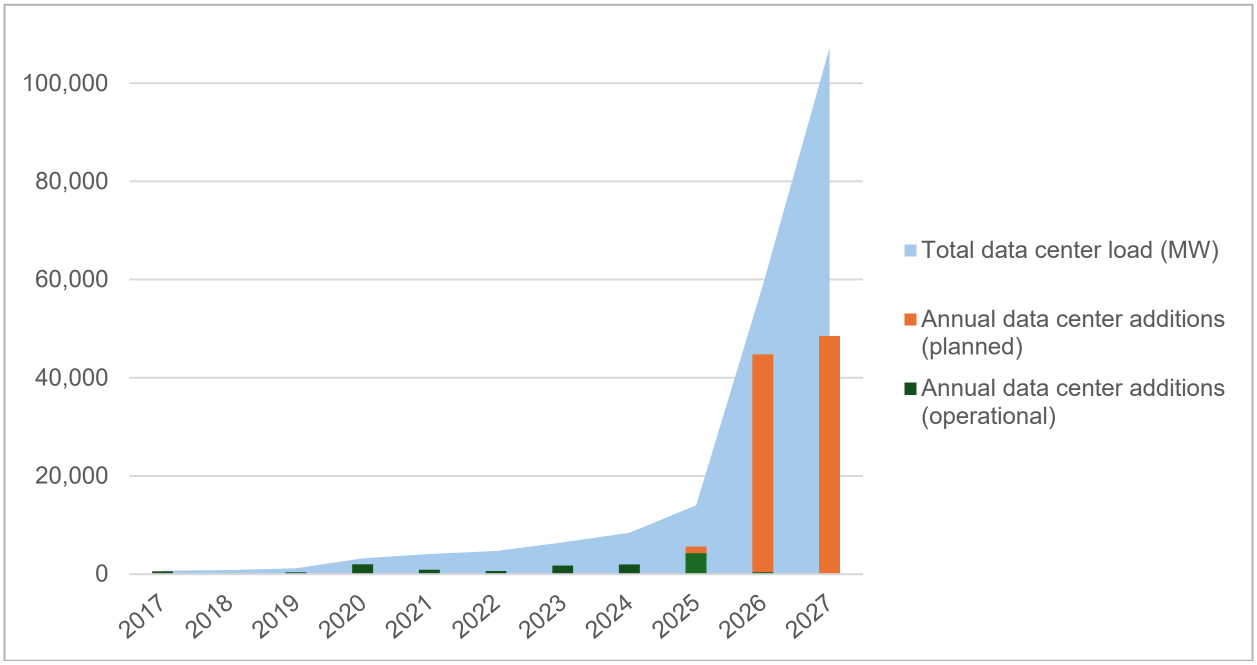
This paper offers a conceptual overview of how BESS can help utilities reduce the risks of cost increases for existing ratepayers from large load growth, especially smaller, rural, and consumer-owned utilities who may face more near-term exposure to these risks. Strategic deployment of BESS combined with effective cost allocation in tariff design can in fact increase the likelihood that new large loads can contribute to reductions in ratepayer bills rather than increases. Its review of potential affordability benefits includes considerations and brief case studies comparing utility-scale, front-of-the-meter BESS, behind-the-meter BESS co-located with data centers, and aggregations of small-scale systems.

1.1 Recent Trends in Load Growth and Electricity Affordability

While forecasts for future data center load growth are uncertain and vary widely, recent deployment has already been significant. Highlighting the scale of recent and near-term growth, Figure 1 illustrates annual data center capacity additions between 2017 and 2027, with "planned" additions representing projects that are not yet operational but have been announced publicly or applied for state permits (Cleanview 2026; Thomas 2025). Recent estimates suggest that data centers could represent between 9-17% of total nationwide electricity demand by 2030, more than double their current share of approximately 4% (EPRI 2026).

Data centers alone currently account for more than 50% of total utility load growth forecasts across the country and a striking 78% of the projected 20-year demand in PJM, the nation's largest regional transmission operator (RTO), even when forecasts are discounted to account for uncertainty (Orelowitz 2026; PJM 2026; Wilson et al. 2025). The Midcontinent Independent System Operator (MISO), which operates the nation's second-largest regional grid, reported in late 2025 that load growth by 2030 appears likely to approach the higher end of the grid operator's 2024 long-term load forecast (MISO 2025).

Figure 1: New and Cumulative Data Center Capacity (MW) in the United States, 2017-2027



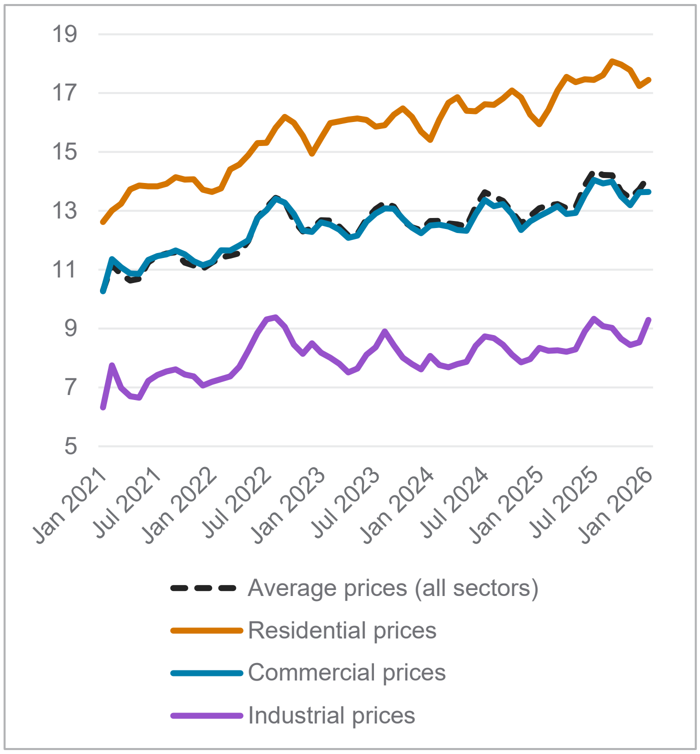
Data source: Cleanview (Cleanview 2026)

New data centers are also increasingly being deployed in rural areas, a shift from previous siting patterns. Analysis from the Pew Research Center suggested that approximately two-thirds of planned data centers will be sited in rural census tracts, compared to only 13% of data centers in operation as of early 2026 (Seets and Radde 2026). Rural areas are more likely to be served by relatively small electric cooperatives or public utilities that operate aging grid infrastructure across their sparsely populated service territories.

Small, rural utilities face more reliability challenges than utilities with denser service territories, and many are reliant on wholesale power market purchases to meet resource adequacy targets (Kuuskvere and Dengler 2024; Pahl 2026; Martucci 2026b). These factors may pose challenges for rural utilities facing a forecasted influx in data center demand. At the same time, many rural utilities and the customers they serve stand to benefit from the revenues that that data centers may bring, even if they must navigate near-term obstacles to accommodate them (Peterson and Cash 2026).

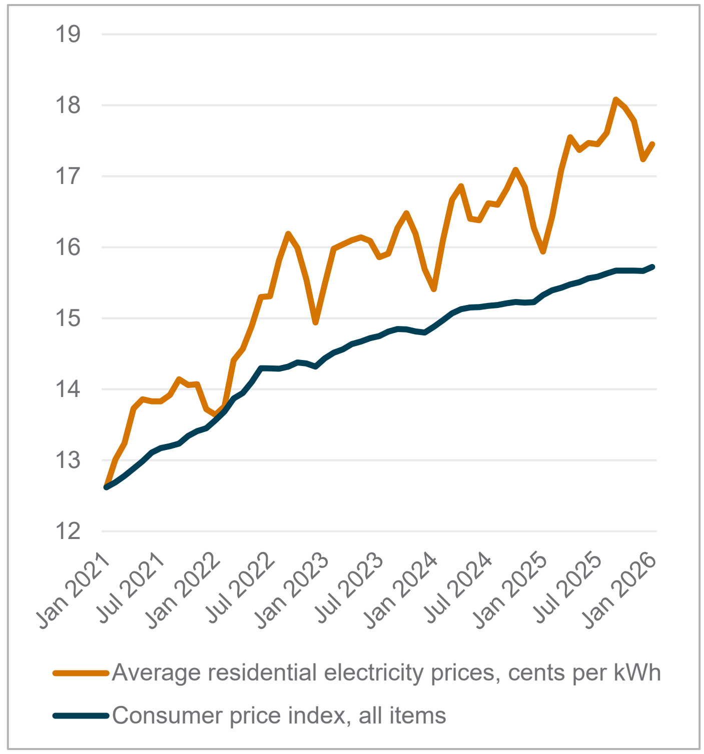
This load growth has coincided with a period of increasing electricity rates across the United States. Average monthly retail electricity prices across all customer classes increased approximately 37.7% in the five-year period between January 2021 and January 2026, as illustrated in Figure 2, and have outstripped the pace of inflation, as shown in Figure 3 (EIA 2025b; Benson et al. 2026). Surveys have emphasized that electricity affordability has become an increasing challenge and source of financial stress for many Americans (PowerLines 2026; EIA 2026a; Green 2026).

Figure 2: Average U.S. retail price of electricity by sector (cents per kWh), 2021-2026



Data source: Energy Information Administration (EIA 2026b)

Figure 3: Residential electricity prices (cents per kWh) as compared to the Consumer Price Index, 2021-2026



Data source: Energy Information Administration and Bureau of Labor Statistics (EIA 2026b; BLS 2026)

These increases have been driven by many factors, and research has not indicated that data centers have been primarily responsible to date (Hledik and Lam 2026; Ryu and Hiatt 2026; Lawson et al. 2026). Data center load growth may even be able to help some utilities help drive rates down, as has been the case during past periods of load growth: higher demand growth has often been associated with retail rate decreases (Wiser et al. 2025; Donohoo-Vallett et al. 2026). However, whether data center load growth ultimately hampers or helps electricity affordability for existing customers depends on several factors. These include:

- the amount of grid infrastructure and other utility expenses needed to accommodate new load (Zeng and Knight 2025; Acharya et al. 2025; Hledik et al. 2026),
- how utilities allocate the costs of that infrastructure among new and existing customers (Benson et al. 2026; Anderson et al. 2025; Bertolacini et al. 2026),
- and how actual long-term load growth compares to forecasts, given the potential mismatch between the rapid pace of data center growth and the longer timeframes of utility planning and grid infrastructure construction (Acharya et al. 2025; Martin and Peskoe 2025; Kavulla 2026; Fagan and Chung 2025).

Various policy, regulatory, and ratemaking approaches have been proposed to help ensure that load growth leads to rate-positive outcomes, including legislation and tariff design to address cost allocation, requirements that data centers procure and pay for their own capacity, and flexible interconnection or curtailment agreements, among others (Anderson et al. 2025; Powell et al. 2025; SEPA 2026; Latitude Intelligence 2026; Nadel 2025; Norris et al. 2025).

The success of these emerging regulatory solutions at enabling affordable data center growth hinges in part on enabling technologies, and energy storage has a vital role to play. Energy storage is versatile and can play many roles: a given project can interchangeably act as generation, load, or provide other grid services at different times depending on its configuration and the needs of the grid (Ribeiro 2026; Twitchell et al. 2026). BESS can, for example, enable load flexibility and reduce the need for some utility investments in higher-cost, slow-to-build grid infrastructure (Kotwis et al. 2025; Hledik et al. 2026; Twitchell et al. 2026). Energy storage can also benefit both utilities and data center developers alike by providing reliability benefits, offering a range of revenue streams, and enabling data centers to more quickly connect to the grid (Mohammadi et al. 2026; St. John 2025; Hledik and Peters 2023; Redwood Materials 2026). These benefits may be especially impactful for the rural and often consumer-owned utilities whose service territories are increasingly targets for data center growth.

2.0 Affordability Impacts of Data Center Load Growth

While electricity prices have climbed steadily upward in recent years, there is limited and conflicting data indicating that data center growth has been a direct driver of increases in residential electricity costs to date. Factors impacting residential prices are complex and vary by state, and include wildfire and storm recovery costs, the impact of policy changes on equipment prices, and the impacts of geopolitical turmoil on oil and gas prices, among others (Hledik and Lam 2026; Wiser et al. 2025). Some utilities with significant data center presence have even credited the new loads for recent approvals of rate decreases for residential customers, including Georgia Power and Portland General Electric (Wozniacka 2026; Georgia Power 2026).

Load growth has the potential to either decrease rates—by increasing the total customer sales across which utilities recover their costs—or increase them—by driving costs upward faster than total demand. Section 2.1 outlines scenarios that illustrate a range of possible outcomes from load growth on customer bills based on utility cost allocation principles. Stated simply, data center growth can be, and has been, rate-positive for residential customers as long as it does not lead to disproportionate cost increases for existing customers. This is a risk, however: the current influx of data centers has already driven wholesale market prices upward, as described in Section 2.2, which has led to bill impacts for customers of utilities more impacted by those prices. The role of specific factors that impact how load growth will ultimately impact a given utility's ratepayer bills, including utilities' exposure to wholesale market volatility, speculative data center interconnection applications, and tariff design are described in Section 2.3.

2.1 An Illustration of Load Growth Scenarios and Potential Price Outcomes

The impact that data centers will have on a utility's overall rates is, at its core, a simple math problem. Utility operations incur various fixed and variable costs. These include rate-based capital costs, such as the costs of building or upgrading grid infrastructure, for which investor-owned utilities earn a regulated rate of return; operating costs, which include fuel costs, wholesale power market purchases, labor, and other materials; and other costs, including taxes and depreciation expenses (Jamison 2007; Davis 2009; Lazar 2015). Utilities then recover these costs from their customers. This basic concept is illustrated by the simplified formula in Figure 4:

Figure 4: Simplified Utility Cost Allocation Formula

$$M_0 = \frac{r(B_0) + C_0}{MWh_0}$$

For any given month, B_0 represents all rate-based capital expenditures, which are fixed costs; r is the utility's return on investment; and C_0 is the sum of all variable operational costs, taxes, and other expenses. In the denominator, MWh_0 is the sum of all customers' total electricity consumption. Dividing total costs by total customer demand gives an average customer monthly bill of M_0.

It should be emphasized that in practice, these costs are not divided evenly among all ratepayers; instead, customers are divided into different classes—generally residential, commercial, and industrial. Many factors determine how different costs are divided among these customer classes, with significant variation between utilities (Lazar 2015). Nonetheless, the simplified formula illustrates the basic principle of utility cost allocation: the costs represented in the numerator are divided among the customer sales represented in the denominator. If demand grows faster than costs, average bills will decrease. Conversely, if cost increases outstrip growth in demand, bills will increase.

2.1.1 Scenario 1: Minimal Load Growth with Increasing Utility Costs Leads to Higher Bills

Consider a situation with nonexistent or minimal load growth, as was the case in recent history: electricity demand in the United States was functionally flat from approximately 2005-2020, with annual consumption increasing by an average of 0.1% per year (EIA 2025a). Even if this pattern of flat demand were to remain stable over the long term, utilities still incur costs: for example, to replace aging infrastructure. In a hypothetical scenario with minimal load growth, a simplified version of utilities' cost allocation equation might look like the formula in Figure 5 below:

Figure 5: Simplified Cost Allocation Formula with Cost Increases and Minimal Load Growth

$$M_1 = \frac{r(B_0) + r(B_i) + C_1}{MWh_0}$$

Here, in a future month, B_i represents the incremental fixed costs associated with new or upgraded infrastructure needed to replace aging assets and maintain reliability, and C_1 represents that month's variable costs. If inflation or other factors lead to per-unit increases in fixed costs (infrastructure investments), variable costs (such as fuel, labor, and wholesale purchases), or both, these incremental costs will be higher than the utility's embedded average costs. The utility's total costs therefore increase. If these higher costs are spread over an unchanged denominator representing total sales of electricity to customers, then new average monthly bills (M_1) for all customers will be higher than their previous average (M_0).

Scenario 1 Implications: Affordability Implications of Off-Grid Data Centers

While this is an extreme example, it highlights a potential affordability risk if many new data centers choose to forgo grid interconnection entirely. Several proposed large loads have announced plans to meet their power demand with self-supplied, behind-the-meter energy instead of connecting to the grid, including a planned data center campus in Texas that intends to power its facilities with more than seven gigawatts of self-supplied power (Gombar 2026; Rissman and Gimon 2026; Halper 2026; Pacifico Energy 2026). Demand for behind-the-meter gas generation has already contributed to spikes in component costs and supply shortages, driving up prices for new plants (Rochas 2026; Rissman and Gimon 2026; Besuner et al. 2025). While off-grid data centers do not directly impose new costs on utility customers in the form of new grid investments to accommodate new load, they still play a role in increasing input costs without contributing to those expenses as utility customers. In a hypothetical wave of data center grid defection, rates for existing customers are likely to increase (Bertolacini et al. 2026; Rissman and Gimon 2026; Ewing 2026).

2.1.2 Scenario 2: Load Growth with Minimal New Utility Costs Leads to Lower Bills

It follows that the opposite extreme, where customer demand grows but expenses do not, will have the opposite outcome. A scenario where data centers drive load growth for a given utility but require no, or very minimal, additional costs, is illustrated in Figure 6 below:

Figure 6: Simplified Cost Allocation Formula with Load Growth and Minimal Cost Increases

$$M_1 = \frac{r(B_0) + C_0}{MWh_0 + MWh_{DC}}$$

Here, the same total costs in the numerator are spread among more customers, thanks to the addition of new data center load (MWh_{DC}) without meaningful additions to utility costs. In this scenario, M_1 is less than M_0, and average customer bills decrease.

Scenario 2 Implications: Affordability Benefits of Increased Grid Utilization

This scenario is exaggerated in that is unlikely that most of the U.S. grid would be able to accommodate the scale of forecasted data center load without any new investments. However, it illustrates the potential affordability benefits of interconnecting new large loads using existing system headroom where possible and allocating all costs associated with new data center entry to those large load customers where new investments are needed. Increasing grid utilization, a measurement of how much of the grid's peak capacity is in use at a given time, can enable the existing grid to accommodate more load. Outside of a limited number of hours at peak demand, the grid is rarely used at its full capacity, and identifying pathways to increase that usage can enable load growth at lower costs to ratepayers (Norris et al. 2025; Bertolacini et al. 2026; Lam et al. 2026). Allocation of the costs of serving large loads to new customers, meanwhile, is a goal of new tariff design requirements in several states, although can be difficult to perfectly achieve in practice (Kavulla 2026; Lam et al. 2026).

2.1.3 Scenario 3: Both Customer Load and Utility Costs Increase, and Bill Impacts Vary

Instead, a utility seeing new data centers deployed in its service territory will likely see both costs and demand increase, as shown in Figure 7:

Figure 7: Simplified Cost Allocation Formula with Load Growth and Cost Increases

$$M_1 = \frac{r(B_0) + C_0 + r(B_{DC}) + C_{DC}}{MWh_0 + MWh_{DC}}$$

B_{DC} represents the incremental costs of new infrastructure required to accommodate new data center load, and C_{DC} represents the additional variable costs—such as fuel and market purchases—needed to serve these data centers. MWh_{DC} represents new data center load.

Here, both numerator and denominator have increased. If demand grows faster than the new incremental costs needed to accommodate that demand, $M_1 < M_0$ despite the increase in utility spending. However, if the incremental costs of the new utility investments needed to accommodate the new data centers (B_{DC} and C_{DC}) grow faster than demand, $M_1 > M_0$ and average rates will increase.

Scenario 3 Implications: Affordability Outcomes Depend on Whether Costs or Demand Grow Faster

Major load growth generally requires some degree of new utility investments to accommodate that load without compromising reliability. The impact of load growth on affordability therefore depends on whether costs outpace demand growth, or the other way around. If demand growth outpaces cost growth, a utility can make investments in upgrades and additions to the grid—investments that may benefit both existing and new customers—while average rates for all decrease. A version of this outcome was described by Georgia Power in its May 2026 rate case, which proposed a decrease in customer rates across classes thanks to a "growing pipeline of large-load customers…helping spread fixed costs across a broader customer base" (Georgia Power 2026).

On the other hand, if costs—whether fixed costs of new infrastructure needed to serve new loads or meet other grid needs, or variable costs such as fuel and wholesale purchases—increase faster than new load, large loads will drive electricity prices higher. Under current conditions, utilities that are heavily reliant on wholesale power market purchases to serve customer demand, true for many rural electric cooperatives and public power utilities, may be more likely to experience this outcome, as some already have. For one example, Washington, DC, which has seen modest local data center growth, saw average residential rates increase by 94% between January 2021 and January 2026, far outstripping the national average increase of 38% (EIA 2026b; Datacenters.com 2026; Data Cent. Map 2026). The District's Public Service Commission (PSC) approved an additional 7% residential rate increase for customers of Pepco, the sole electric utility serving the District, which is slated to take effect in July 2026. The PSC cited record-high PJM capacity prices, a result in large part of rising data center demand, as the primary driver of these continued increases (DCPSC 2026).

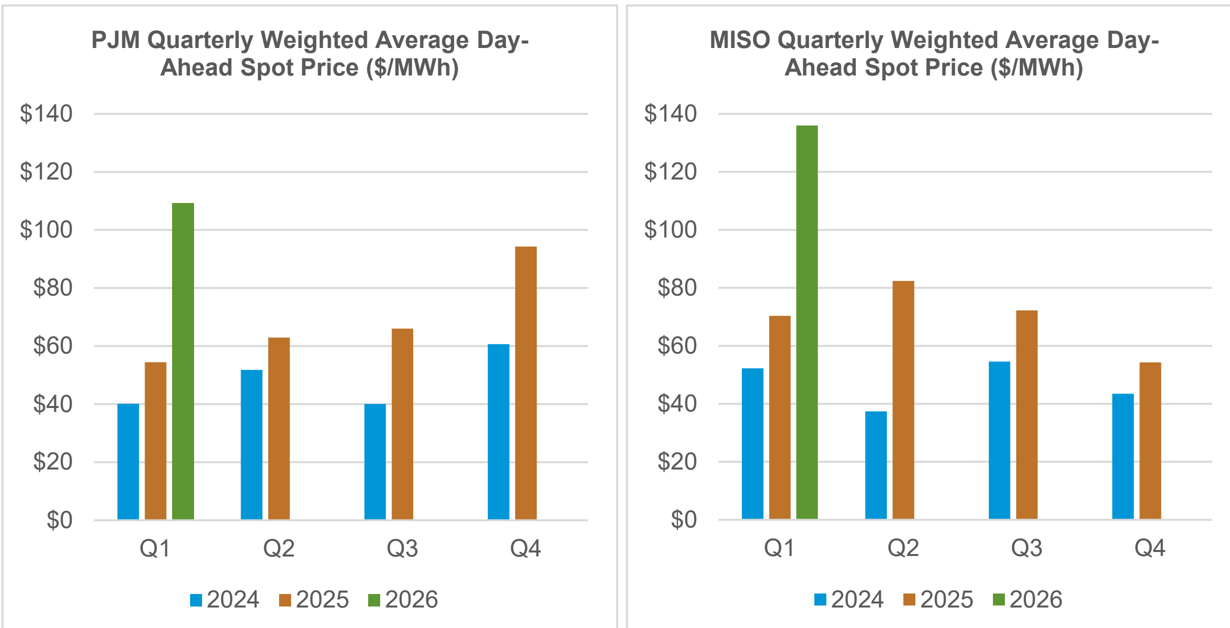
2.2 Impacts of Data Center Growth on Electric Rate Inputs

Large load growth has been associated with cost increases for specific components of electricity bills, including some equipment costs and, perhaps most significantly, wholesale power market prices. Wholesale energy and capacity costs in several markets have spiked upward and shown increased volatility, a result of demand outpacing the supply needed to maintain resource adequacy targets (NERC 2026a).

Average prices in both PJM and MISO's day-ahead energy markets were higher in every quarter in 2025 compared to the same quarter in 2024, and both reported a further spike in first-quarter 2026 prices, as illustrated in Figure 8 (EIA 2026c). In PJM, capacity market prices were also 76% higher in the first quarter of 2026 as compared to the same quarter of 2025, an increase that analysts noted would have been even higher without the recent adoption of a maximum price cap (Monitoring Analytics, LLC 2026; Marshall 2026). PJM has identified data centers as the chief reason for these increases, as described in its market monitor's first-quarter

2026 report: "The price impacts on customers have been very large and are not reversible…[and] will be even larger in the near term unless the issues associated with data center load are addressed in a timely manner…Data center load growth is the primary reason for recent and expected capacity market conditions, including total forecast load growth, the tight supply and demand balance, and high prices." The report concluded that this market tightening in response to data center load directly resulted in a $13.7 billion increase in total electricity costs for PJM's millions of customers (Monitoring Analytics, LLC 2026).

Figure 8: Quarterly Weighted Average Day-Ahead Spot Prices for PJM and MISO



Data source: Electricity Monthly Update March 2026 (EIA 2026c)

Market prices are, naturally, driven by the balance between supply and demand, and the current period of load growth has coincided with a tightening of available supply, thanks to high equipment and construction costs and timeline delays for deploying new grid-scale generation and transmission infrastructure (Besuner et al. 2025; Wiser et al. 2025; Rand et al. 2024). These delays in new capacity additions are generally driven by a combination of interconnection queue bottlenecks, permitting challenges, and supply chain bottlenecks (Rand et al. 2024; Ansolabehere et al. 2024; Gorman et al. 2024).

Data center growth has also contributed to some of these cost pressures on new capacity additions, although it is not the only factor. Capital costs for gas plants, for example, doubled between 2024 and 2026, outpacing projections, while lead times for turbines can stretch five years or more (Besuner et al. 2025; Rochas 2026). These cost increases and delays have themselves been exacerbated by growing demand for new gas plants, both by utilities planning new capacity additions to meet load growth forecasts and by data center developers building behind-the-meter generation (Rochas 2026).

In response to these conditions, utilities in some regions have delayed planned retirements of aging coal-fired generation and other power plants in order to maintain resource adequacy in the face of growing demand, but the high relative costs of operating these older plants has further contributed to upward pressure on rates (Tosado et al. 2025).

Notably, one 2026 analysis concluded that while data center growth to date has had no measurable impact on average residential prices for customers of investor-owned utilities, it has driven modest rate increases for consumer-owned utilities. The study found that a doubling of data center capacity was associated with an average bill increase of 0.42% for cooperative utilities and 0.63% for public utilities, with more significant increases found in specific states and regions. Consumer-owned utilities in parts of Texas, New Mexico, Tennessee, Nebraska, North Dakota, and several PJM states in the mid-Atlantic region have seen data center growth drive monthly bill increases of four to six dollars per month. These utilities' relatively greater reliance on wholesale power markets, and therefore greater exposure to wholesale price volatility, was identified as a primary reason for these impacts (Ryu and Hiatt 2026).

2.3 Additional Factors Shaping Affordability Outcomes

Several additional factors can impact the relationship between large load growth and affordability outcomes for other utility customers. As noted above, these include a utility's degree of exposure to wholesale market prices as well as the scale of its need to invest in high-cost infrastructure upgrades, including large-scale transmission and distribution investments. The accuracy of load growth forecasts can significantly impact long-term customer cost outcomes. Finally, another key factor is the utility's approach to cost allocation and tariff design, which determines what proportion of its fixed costs are paid for by different customer classes.

Many utilities nationwide have included new large loads in the scenario forecasts used to inform planned resource investments, including new asset construction and market purchases. While large load growth is undeniably significant and occurring very quickly, uncertainty about the actual scale of load growth over the years to come, as well as the operational lifespans of many new data centers, have the potential to skew the customer impacts of planned utility investments. "Speculative" applications, where a developer submits multiple interconnection applications for the same project in order to gauge information about cost and speed differences at potential sites, is common among data center developers concerned about time to power (Giacobone 2025; Paccou and Wijnhoven 2025; Quint et al. 2025). Some researchers have raised concerns that speculation is driving load growth estimates upward, with one study suggesting that current forecasts may be nearly ten times actual long-term load growth (Giacobone 2025; Bakalar 2025; Paccou and Wijnhoven 2025).

Virginia's Dominion Energy, the utility with the greatest concentration of data centers in its service territory nationwide, published an addendum to its 2024 Integrated Resource Plan (IRP) indicating which planned generation, transmission, and distribution investments were forecasted due to planned data center entry and which were planned due to load growth from other sources (Dominion Energy 2024). Dominion's forecasted load growth between 2024 and 2038 is approximately 3% per year with data centers, but only 0.5% without them (Acharya et al. 2025; Dominion Energy 2024). Analysis from Pacific Northwest National Laboratory suggested that, assuming an average asset lifespan of 30 years, Dominion ratepayers could be responsible for $5 billion in stranded assets even if 80% of forecasted load materializes. This stranded investment risk is much higher if actual load growth is even lower, as shown in Figure 9 (Acharya et al. 2025)

Figure 9: Load Growth Uncertainty and Stranded Asset Risk Scenarios

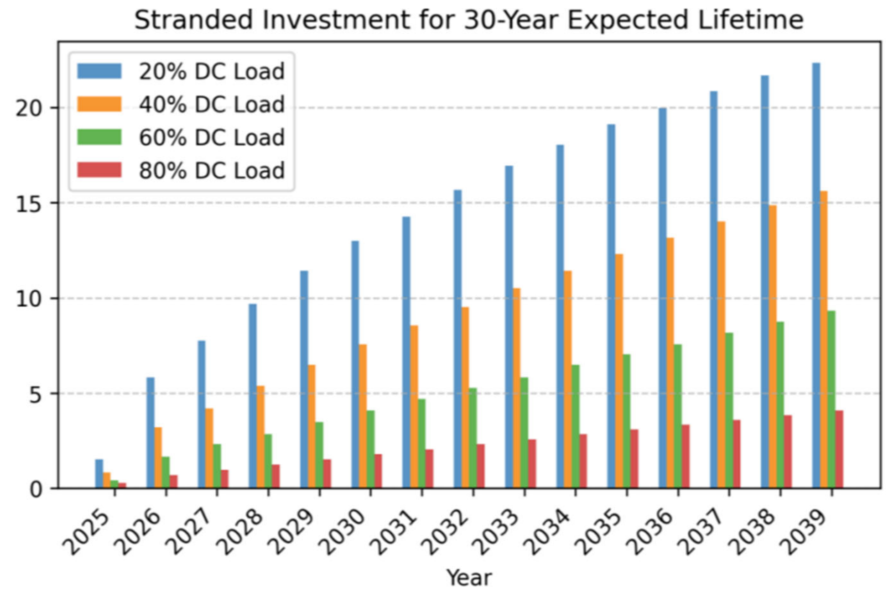


Figure Source: Measuring the Cost of Potential Stranded Assets from Speculative Large Load Interconnection Requests (Acharya et al. 2025)

Finally, a utility's approach to cost allocation can be a key factor in determining the impacts of large load growth on customer affordability. Many utilities have implemented tariff structures designed to minimize cost shifts to other ratepayers from infrastructure upgrades needed to accommodate data centers, whether voluntarily or in compliance with requirements established by regulators or legislation (Perez et al. 2025; SEPA 2026; Anderson et al. 2025). These tariffs commonly require that large-load customers pay for a percentage of contracted transmission or generation demand over a defined "take-or-pay" contract period, even if actual use is lower (Kavulla 2026). Other protections include collateral requirements, in which large-load customers must demonstrate financial security and creditworthiness as a protection against speculative applications and premature exits; exit fees, where a customer must pay a utility if it exits service before a determined time period; and capacity reassignment provisions, where existing large-load customers are held responsible for transferring part of their contracted capacity to another customer (Perez et al. 2025; SEPA 2026).

For example, a tariff approved in 2025 for AEP Ohio requires new data centers to pay for at least 85% of the energy they subscribe to use over a minimum required contract period of 12 years (AEP Ohio 2025). A large-load tariff approved in 2025 for Dominion Energy, the utility with the highest nationwide proportion of data centers in a single service territory, requires that any customers who request more than 25 MW of service provide $1.5 million in collateral per MW of capacity and pay 85% of contracted transmission demand and 60% of contracted generation demand, regardless of actual use, over a 14-year minimum contract period (Nolette 2026).

In summary, a utility can minimize cost shift risks and maximize the potential for large load growth to be positive for affordability if it can effectively hedge against speculation, protect ratepayers from wholesale market price spikes, and effectively allocate costs associated with new data center load growth to those data center customers. While a combination of approaches is needed for most utilities to ensure optimal outcomes, strategic deployment of battery energy storage combined with tariff design can provide significant affordability benefits to existing ratepayers, as explored in Section 3.0.

3.0 The Role of Battery Energy Storage as an Affordability Asset

Against a backdrop of increasing but uncertain load growth, sharp increases in wholesale power prices, and rising electricity rates, battery energy storage systems have emerged as a key tool for maintaining customer affordability. In general, batteries can offer a suite of potential economic benefits to utilities and their ratepayers:

- **Grid utilization and cost deferral:** Thanks to its abilities to shift loads and shave system peaks, BESS can help enable greater utilization of existing grid infrastructure, enabling utilities to defer investments in new generation, transmission, and distribution infrastructure. BESS can also reduce dependence on, or even replace, high-cost peaker plants (Aurora Energy Research 2025; Shah and Pal 2026; Chew et al. 2018; Norris et al. 2025; Robinson et al. 2021; W. Brown et al. 2023; Twitchell et al. 2026).

- **Hedge against volatile wholesale market prices:** BESS can "shave" system peaks by charging during periods of low prices and discharging during periods of peak demand, which can help reduce market peak demand prices (Din 2026; Twitchell et al. 2026; Inaolaji et al. 2024). Discharging from a battery (or aggregation of smaller batteries) can reduce a utility's need to purchase market power when prices are highest (Convergent Energy and Power 2024).

- **Market revenue opportunities:** Many energy storage systems can also offset some of their direct upfront costs with revenues from market participation, such as from ancillary services and energy arbitrage (Turan and Cole 2024; Bonner 2025; Twitchell et al. 2026). While opportunities vary by market, batteries may be able to stack multiple revenue streams, including capacity, energy, and ancillary services market payments, further improving the potential economics of a BESS project (Aurora Energy Research 2025; Lazard 2025).

- **Reliability benefits:** BESS can provide critical reliability benefits to the grid, including smoothing spikes in data center loads that can occur during AI training and reducing growing reliability risks from sudden load departures (Mohammadi et al. 2026; NERC 2025b; Singh et al. 2018; Twitchell et al. 2026). Some of these reliability offerings can be compensated via ancillary services markets.

- **Resilience benefits:** Customer-sited behind-the-meter (BTM) batteries can maintain power to customers in the case of a grid outage, avoiding costs including, for example, food or medicine that would spoil without refrigeration (Kerby 2025; Moncheur de Rieudotte and Kerby 2025). Utility front-of-the-meter (FTM) batteries can offer black-start capabilities, allowing the grid to quickly resume operations after an outage (Kerby 2025; Nguyen et al. 2025).

Some of these benefits, including batteries' ability to defer high-cost grid investments by improving grid utilization and their role in reducing utilities' exposure to high wholesale prices, are especially valuable to utilities facing the risk of potential cost shifts from rapid but uncertain large load growth. These benefits are described in more detail in Section 3.1. Since batteries can be deployed in many sizes and configurations—as large-scale utility assets, as small distributed systems that can sometimes be aggregated to function as a single grid asset, or co-located at a data center as a "bring-your-own-capacity" (BYOC) solution—additional tradeoffs between each of these approaches, while not mutually exclusive, are discussed in Section 3.2, with emphasis on considerations relevant to smaller, consumer-owned utilities with rural service territories. Finally, key costs, benefits, and tradeoffs of energy storage as compared to alternative pathways to meet capacity needs are summarized in Section 3.3.

3.1 Affordability Benefits of Energy Storage in the Context of Data Center Load Growth

While battery storage can offer affordability benefits to ratepayers under various grid conditions, some BESS capabilities offer particular value to utilities grappling with the risk of increased costs from new large loads. These include batteries' ability to defer higher-cost investments in new grid infrastructure by enabling higher utilization of existing resources and limited curtailment of large loads; their ability to reduce ratepayer exposure to high and volatile wholesale market costs; and their grid reliability contributions in the face of some of the unique reliability risks posed by the characteristics of AI data centers.

3.1.1 Cost Deferral and Flexibility

One of the primary ways that energy storage can support affordability outcomes for ratepayers comes from batteries' ability to enable higher grid utilization under a variety of scenarios, enabling additional load to interconnect to the existing grid with a reduced need for investment in costly upgrades to transmission lines and other system investments that would otherwise be needed to meet increases in peak demand (Shah and Pal 2026; Hledik et al. 2026; Twitchell et al. 2026).

While the grid has traditionally been built to accommodate peak demand, actual grid usage rarely approaches this limit, with some research estimating that average grid utilization in the United States is between 50-65% of peak system capacity (Oikonomou et al. 2024; Shah and Pal 2026; Twitchell et al. 2026). As a result, ratepayers are paying for infrastructure that is rarely used. Energy storage can help enhance utilization of existing assets and reduce the need for investments in larger-scale, higher-cost infrastructure that would otherwise be needed to increase the grid's overall capacity to meet forecasted peaks. Storage can therefore allow utilities to accommodate new load more quickly and with fewer added costs for ratepayers.

FTM storage and appropriately configured distributed storage can reduce congestion on the transmission system by charging when demand is low and then injecting additional capacity into the grid by discharging at times of peak demand, reducing the need for new transmission lines to accommodate peak demand increases. Deploying energy storage has been shown to cost ratepayers millions of dollars less than transmission line upgrades in numerous case studies (W. Brown et al. 2023; Chew et al. 2018; Twitchell et al. 2026). This capability can also allow storage to defer large investments in distribution or generation infrastructure (Twitchell et al. 2026).

BTM storage co-located with a data center, meanwhile, can directly enable large load flexibility. Storage allows loads to curtail their use of grid power during peak demand by using their battery, which can in some cases be paired with additional on-site generation capacity, to power critical operations without straining the grid (O'Dea 2026; Norris et al. 2025). One 2025 study estimated that the United States' grids could accommodate nearly 100 GW of additional load by curtailing only 0.5% of maximum potential consumption for less than 200 hours a year (Norris et al. 2025). "BYOC" storage and a commitment to curtail at times of highest demand can be required or incentivized in interconnection agreements, offering new large loads a potentially years-faster pathway to grid interconnection while minimizing the risk of cost shifts to existing ratepayers (Powell et al. 2025; Spector 2025; Brancucci et al. 2025).

BESS's ability to be deployed incrementally and enhance utilization of existing assets can also help utilities hedge against uncertain load growth forecasts, protecting ratepayers from the risk of over-investing in assets that may become stranded if growth does not materialize as forecasted. An energy storage non-wires alternative (NWA) pilot in Boothbay, Maine offers a case study of this affordability benefit in practice. After utility forecasts in 2008 had identified the need for a $1.5 billion transmission line upgrade to meet forecasted peak demand increases, the Maine PUC ultimately approved an NWA pilot as a more cost-effective alternative to part of the upgrade. The project included a 500 kW/3 MWh BESS and was deployed in 2013. In 2018, after the forecasted load growth had not materialized at the scale originally forecasted, the pilot project was retired due to lack of need. Ratepayer savings were estimated at $12 million and avoided long-term payments for a transmission investment that would have otherwise become a stranded asset (Chew et al. 2018; Twitchell et al. 2026).

3.1.2 Wholesale Market Price Insulation and Peak Shaving

BESS can also reduce the impacts of wholesale market price increases, both by offering utilities a lower-cost capacity alternative to expensive spot market purchases and by contributing to reductions in system-wide peak prices, driving down costs for all. These functions can protect affordability for customers of utilities with forecasted large-load growth and utilities who do not anticipate new data center entries into their service territory but are nonetheless impacted by wholesale price increases driven by market-wide demand growth (Pahl 2026).

Wholesale demand charges paid by a utility to a wholesale power supplier, like retail demand charges paid to a utility by retail customers, are generally based on the hour of highest demand in a given month. If a utility uses BESS to "shave" its peak demand on the grid, these demand charges, which can be significant, can be reduced (Martucci 2026b; Inaolaji et al. 2024). One electric cooperative in Tennessee deployed FTM batteries in 2026 largely to reduce wholesale costs, noting that monthly demand charges from the Tennessee Valley Authority can often represent one-third of the cooperative's total wholesale power purchase costs (Martucci 2026a, 2026b).

When batteries shave peak demand by discharging during peak periods, allowing loads to curtail by switching to BESS as a source of backup power, or both, they can also help reduce dependence on costly peaker plants. Peaker plants, which are typically powered by gas, or sometimes by diesel or other fuel sources, are characterized by their ability to come online quickly in response to demand spikes. They also have some of the highest operational costs of all generating assets on the grid (EIA 2012; Lazard 2025; Twitchell et al. 2026; Aurora Energy Research 2025). Unlike typical baseload generators, which operate continuously, peakers are dispatched only during periods of highest demand when lower-cost generators are already in use or unavailable. By reducing the use of high-cost peakers, BESS can help lower overall wholesale prices (Twitchell et al. 2026). Utility-scale BESS are already directly cost-competitive with peaker plants even without accounting for tax incentives that may be available to certain storage systems (Dueñas et al. 2024; Lazard 2025). BESS also do not incur fuel costs, offering additional savings and reduced exposure to fuel price volatility (Lazard 2025; Twitchell et al. 2026; KPP 2022).

3.1.3 Reliability Benefits in the Context of Large-Load Risks

The North American Electric Reliability Corporation (NERC) has issued several reports and alerts warning about the risks that certain operational characteristics of AI data center loads pose to grid reliability. These include rapid, “spiky” usage fluctuations and rapid load losses due to data centers’ voltage sensitivity (NERC 2026b, 2025a). Batteries can address these reliability challenges and can do so quickly, often responding in near real-time. From an affordability perspective, it is notable that BESS can help address these emerging grid risks in addition to offering the services and benefits described in this report, enhancing the overall value of a given project. Furthermore, some aspects of BESS’s contributions to grid reliability may be compensated as ancillary services, offering additional revenues to help utilities further reduce the costs of a BESS investment to ratepayers (Rawlings 2026; Mohammadi et al. 2026; Modo Energy 2026). Meanwhile, BTM batteries co-located with a data center are particularly well-positioned to mitigate large load reliability risks with no or minimal cost to existing ratepayers.

Batteries can use their ability to charge or discharge in response to demand conditions, and furthermore, in response to much more rapid, smaller-scale fluctuations in demand that are a characteristic of data centers conducting AI model training (Mohammadi et al. 2026; NERC Large Loads Task Force 2025; Dukosi 2025). These “spiky” data center loads can threaten the reliability of the grid (NERC Large Loads Task Force 2025; NERC 2025b). BTM batteries at a data center site can “smooth” these loads before they impact the grid, and can respond more quickly than other technologies, mitigating reliability risks (NERC 2025b; Simonian 2025).

Many AI data centers are also particularly sensitive to relatively small voltage fluctuations in the grid. As a result, they are more likely than other loads to quickly disconnect from the grid and switch to backup power in response to minor voltage faults. Significant and unexpected load losses can impact the voltage and frequency of the grid, raising the risk of cascading outages (NERC 2025a). Two high-profile incidents in Virginia in 2024 and 2025, where large data centers suddenly disconnected from the grid, led NERC to issue a highest-level reliability alert in 2026 (Walton 2026; NERC 2025a, 2026b).

BTM batteries with grid-forming inverters can be deployed to reduce the likelihood of these data center load losses by providing low-voltage ride-through (LVRT) support; BESS has previously been deployed in many cases to address similar LVRT challenges for variable generation (Sakib et al. 2025; Xie et al. 2025). FTM or BTM batteries can also reduce the likelihood of cascading outages if load losses do occur by quickly charging from the grid, effectively replacing the lost load for the duration of the disruption (Campbell and Miller 2026; NERC 2025b).

3.2 Evaluating Different Energy Storage Deployment Pathways

Energy storage can be deployed in several different ways, including large-scale, front-of-the-meter (FTM) utility-operated systems; behind-the-meter batteries co-located with a large load; and small-scale distributed systems owned or leased by customers, which can be aggregated together to function as a single, larger grid asset. Each configuration offers a range of benefits and tradeoffs.

Some considerations, cost aspects, notable benefits, and tradeoffs for each approach are described in more detail below and summarized in Table 1. These include upfront costs: for example, larger FTM batteries are cheaper per kW or kWh than smaller systems, but these projects may incur additional expenses due to interconnection and permitting processes and risk delays. A BTM battery supplied by a data center customer imposes no direct costs to ratepayers, but does not offer a utility additional grid benefits or revenue opportunities unless required in an interconnection agreement. Furthermore, requiring new data center customers to supply their own BTM capacity is not an option for utility that does not anticipate new data center customers in their service territory but has still seen retail prices impacted by the regional market impacts of load growth. Aggregations of small residential and/or commercial batteries can be very fast to deploy and offer additional resilience value to participants, but a utility's ability to use aggregated small-scale systems to serve broader grid needs may be limited by scale and the need for enabling technologies and expertise.

Importantly, these options are also not mutually exclusive: requiring an interconnecting large-load customer to provide onsite BESS does not preclude a utility from deploying FTM BESS or aggregating distributed systems. Each of these energy storage configurations offer opportunities for utilities to increase grid utilization, hedge against volatility, and potentially defer costlier investments for ratepayers. All can therefore help reduce the risk of cost shifts and make load growth likelier to be rate-positive for existing utility customers.

Table 1: Benefits, Costs, and Key Considerations for Utility-Scale BESS, Customer-Sited BESS, and Aggregated Distributed BESS

Front-of-the-meter (FTM) utility-scale BESS	Behind-the-meter (BTM) BESS at data center	Aggregated small-scale customer-sited BESS
• Large-scale batteries sited on utility side of meter • Can be sized to meet peak demand increase from forecasted data center additions (typical 4-hour duration enough to meet most peak periods) • Rate-based asset, costs recovered from ratepayers • Costs can be partially offset by market revenue in some regions • Can hedge against volatile wholesale market prices and defer more expensive transmission or distribution upgrades • Capital costs higher for longer-duration systems, but continue to decline; per-kW and kWh costs are lower for larger batteries • May face interconnection and permitting delays, particularly for larger systems	• Battery sited at data center on customer side of meter • Costs borne by data center, not ratepayers • Not utility asset for other grid needs, and utility does not earn market revenue • Can enable data centers to curtail loads by switching to BESS as backup power during peak demand, increasing utilization and reducing new costs; flexibility can be required by interconnection agreement • Enabling technologies and software can help batteries offer real-time reliability support, including load smoothing and voltage support • Faster to deploy than FTM systems; reduced interconnection and permitting challenges	• Consumer-owned small-scale BESS, can be aggregated to behave as a single, larger utility asset • Relatively low costs shared by customers, utility, aggregator; approaches vary • Aggregator and participants earn revenue; customers can receive incentives for participation • Enables direct flexibility of participating loads; offers peak shaving and can defer other investments • Resilience benefits for participants • High operational complexity, requires software and enabling technologies • Ability to meet grid needs depends on scale; consider number of utility customers and program and technology adoption levels • Can be very quick to deploy; smallest systems face minimal interconnection and permitting challenges

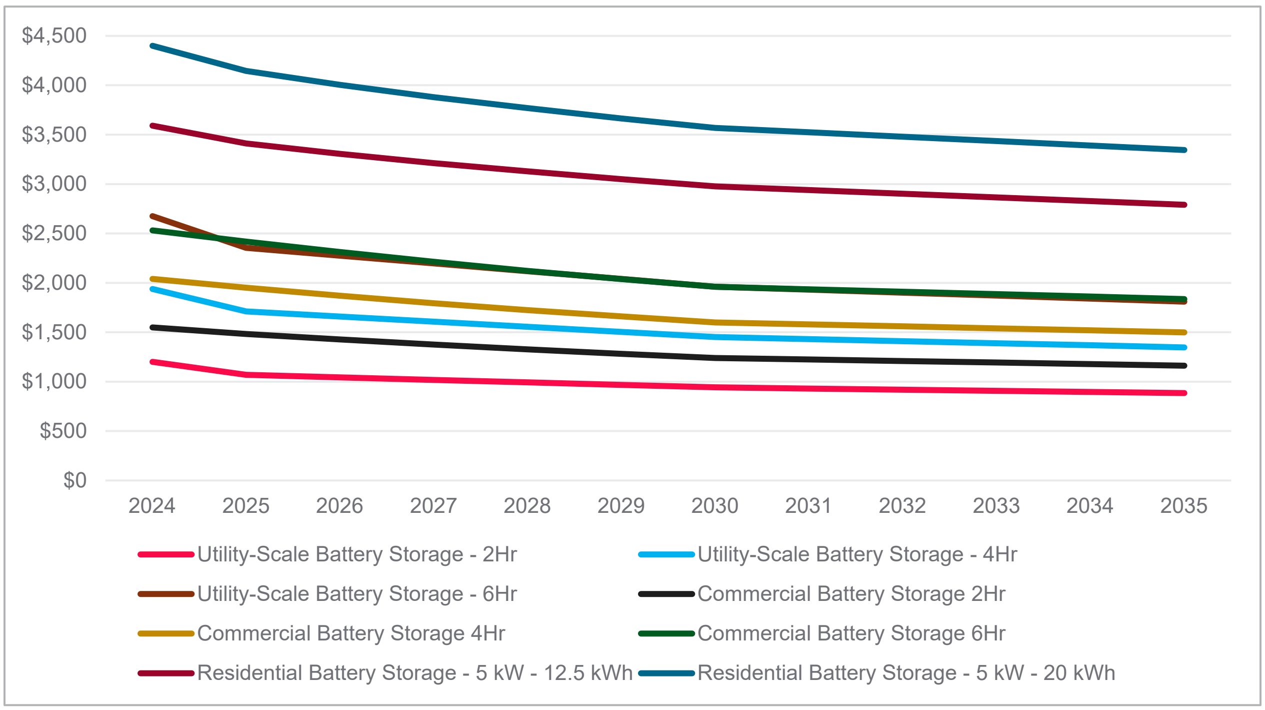
3.2.1 Utility-Scale Front-of-the-Meter Energy Storage

Utilities can deploy FTM grid-scale battery storage to meet various grid needs, including as an NWA to larger, slower, and more expensive grid upgrades. The scale of systems that can constitute “utility-scale” or “grid-scale” BESS varies: the U.S. Energy Information Administration (EIA) considers any system with a nameplate capacity of 1 MW or greater to be “utility-scale,” although some projects can have a capacity of hundreds of MW. The median capacity of a utility-scale BESS in the United States as of early 2026 was approximately 10 MW (EIA 2026b). Depending on their size, a utility-scale BESS may be connected to the transmission or to the distribution system.

The costs of a utility-owned BESS, like any capital investment, are recovered from ratepayers, meaning investing in a new BESS project is likely to impose at least some costs on existing customers. If a BESS procurement is driven by the entry of a new large load, however, a utility may use tariff design to allocate some or all of the system’s up-front costs to the large load customer. Utility-owned BESS can also be a solution for utilities that are not anticipating new large load entry into their service territory, but are interested in hedging against the impacts of load growth and other factors on regional wholesale power market and fuel cost volatility (Pahl 2026).

Capital costs for BESS remain relatively high, and these up-front costs have been a deterrent against more widespread deployment of batteries as an NWA. However, costs are decreasing rapidly: the global cost of lithium-ion batteries fell by 90% between 2010 and 2020, making BESS increasingly cost-competitive with alternatives (Kaps and Layne 2026; Cole et al. 2025). Larger BESS also generally have lower costs per-kWh than smaller-scale systems, as illustrated in Figure 10. As previously mentioned, batteries can also earn revenues via energy, capacity, and ancillary service markets, depending on the region and market, or through energy arbitrage transactions, which can offset some of their upfront costs. BESS can also offer savings on fuel costs: in one case, a 1 MW/4 MWh battery saved a municipal utility in Kansas $3,000 per day in fuel costs by replacing usage of a 1 MW diesel generator, in addition to providing energy arbitrage revenues (KPP 2022).

Figure 10: Projected Capex for Different Battery Energy Storage Systems, 2024-2035, Moderate Scenario ($/kWh)



Data Source: National Laboratory of the Rockies Annual Technology Baseline Database, 2024 (Mirletz et al. 2024)

Many case studies have shown that batteries deployed at congested locations can be more cost-effective for ratepayers than upgrades to or construction of new transmission or distribution lines. BESS projects can be sized to meet forecasted peak demand increases for a given duration by charging when prices and demand are low and then discharging to the grid when their additional capacity is needed. Four-hour durations are common for grid-scale batteries, and most peak demand periods are typically four hours or less. Although system costs are typically higher as battery durations increase, four-hour batteries receive higher capacity credits in most wholesale markets compared to batteries with shorter durations, which may help a utility offset some up-front costs (CAISO 2025; Weaver 2026; FlexGen 2025).

The ability to size utility-scale BESS to meet incremental peak demand growth enables higher utilization of existing grid assets outside of peak periods, allowing the grid to efficiently accommodate more load without overbuilding (Cooke et al. 2019; Steinberger et al. 2024). As a result, even though per-kW and per-kWh costs of a BESS may be higher than some alternatives, a BESS solution can often meet a given capacity need at a much smaller size than traditional transmission and generation solutions, resulting in lower total costs when compared to alternatives. These savings can be especially pronounced in rural and remote utility service territories, where the total costs of new power lines, for example, can be particularly high due to long distances, rugged terrain, and other access challenges (Twitchell et al. 2026; Kerstein 2025; Ross et al. 2018).

In addition to capital costs, challenges faced by larger-scale FTM batteries can include interconnection delays for transmission-connected systems, siting challenges for large projects, and permitting delays driven by local opposition (Hill 2025; Powell and Twitchell 2026; Powell et al. 2024; Rand et al. 2024). Some utilities have also deployed networks of smaller-scale, distribution-connected batteries that are still utility-owned and operated in order to sidestep some of the deployment challenges of large projects (Martucci 2026c).

Several utilities have deployed utility-owned and -operated FTM batteries to quickly accommodate new data center load. In some of these cases, the utilities have also announced commitments to allocate all or most project costs to large load customers. For example:

- In 2026, the Michigan Public Service Commission (MPSC) approved rate recovery of six FTM BESS projects by DTE Electric. Three of those projects, with a total capacity of 332 MW, will be used to serve a 1,383 MW data center. The PSC approval included cost allocation intended to safeguard existing ratepayers from costs associated with accommodating the new data center load; the data center developer will bear all costs over a 15-year contract period. All six projects will be owned and operated by DTE Electric (MPSC 2026).

- In 2024, Arizona utility Salt River Project began commercial operations of a 4-hour, 300 MW/1,200 MWh BESS project co-located with variable generation. Meta signed a power purchase agreement (PPA) to secure most of the power from the facility for a planned data center, with remaining capacity available to serve existing utility ratepayers (Heynes 2024).

3.2.2 Aggregated Small-Scale Customer-Sited Energy Storage

Small-scale residential or commercial and industrial (C&I) batteries and other small-scale resources can be aggregated together to equal the capacity of one larger system without the siting, permitting, or interconnection delays that may pose challenges for FTM BESS (K. Brown 2023; Powell et al. 2024). These aggregations can be cost-effective and very quick to deploy, and many models exist for asset ownership and operation. A program may use utility-owned batteries that customers lease, with Green Mountain Power’s program in Vermont as one notable example, or may aggregate customer- or third-party-owned batteries (Slanger 2025; Olinsky-Paul 2026). Deployment of BTM batteries throughout a utility’s service territory can provide resilience benefits to participating customers, including mitigating the costs of lost food, medicine, or wages from a power outage; these resilience benefits may be of particular value to customers of rural utilities, who may be more likely to experience more frequent and longer-duration power outages (Mills and Olinsky-Paul 2025; Macmillan et al. 2023; Moncheur de Rieudotte and Kerby 2025).

The ability of aggregated small BESS to act as a solution to peak demand growth from new large loads and the speed at which they can be deployed depends on many factors, including the size of a utility's customer base, customers' willingness to participate in a program, and the need for additional enabling technologies, all of which may pose barriers to deployment at scale for smaller utilities with fewer resources (CFC 2026). However, many small and consumer-owned utilities have successfully deployed aggregated small-scale batteries for resilience, reliability, and affordability benefits (Olinsky-Paul 2026; Martucci 2026b).

Like FTM batteries, small systems can be deployed and aggregated whether or not a given utility is anticipating new data center customers to enter its service territory. If a utility is planning to interconnect new data centers, these large loads may also be able to participate in an aggregation program. Some data center developers have also proposed funding distributed batteries for other customers, although deployment of this approach is limited to date. Examples of aggregation programs deployed in the context of recent peak demand growth include:

- Voltus, a third-party aggregator, announced plans to collaborate with data centers on deployment of aggregations of existing distributed systems to meet demand growth, including agreements for data centers to fund aggregations as an alternative "bring your own capacity" (BYOC) approach. In June 2026, the company announced a partnership with Google in which Google plans to fund the operation of a 100-MW aggregation operated by Voltus in PJM (Khaldi 2026; Voltus 2025).

- Guadalupe Valley Electric Cooperative (GVEC), a rural electric cooperative utility in Texas, has partnered with developers Base Power and Tesla to develop aggregated residential and C&I battery capacity in its service territory (Walton 2025; Johnson 2025). Customers voluntarily sign up to participate in the program and receive up-front rebates and annual compensation to help offset the cost of the battery, including any resilience and bill savings benefits. In exchange, GVEC can directly operate the batteries when needed. While not explicitly driven by data center entry, GVEC can use the aggregated systems to reduce transmission costs, avoid energy purchases during wholesale power market price spikes, and earn market revenues from energy arbitrage in order to support affordability for all ratepayers (Walton 2025).

3.2.3 Data Center-Sited Behind-the-Meter Energy Storage

Utilities may also use tariff structures or interconnection agreements to require new large loads to bring self-supplied generation and/or storage to meet all or part of their forecasted demand, an approach often referred to as a "bring your own capacity" (BYOC) requirement. Under this approach, data centers procure and pay for onsite BTM BESS to fully or partially offset the amount by which they would increase the system's peak demand, but still pursue grid interconnection, use grid power outside of peak hours, and contribute to overall utility costs. BYOC requirements have increasingly been included in new large-load tariffs or policies (SEPA 2026; Anderson et al. 2025). In other cases, BYOC has been used as an incentive to data centers to allow them to interconnect to the grid more quickly, even if self-supplied capacity is not explicitly required. For example, Southwest Power Pool (SPP) offers pathways for faster interconnection to new large loads who are willing to curtail their grid usage during periods of peak demand and/or supply the additional generation capacity needed to accommodate them (SPP 2025; Powell et al. 2025)

From a utility perspective, requiring BTM BESS as part of a BYOC agreement can both enable data centers to interconnect without major delays and help reduce the need for new, rate-recovered infrastructure investments to accommodate data center load. These agreements require data centers to supply at least some needed capacity at their own expense. In addition to avoiding new direct costs for utility customers, BTM BESS can offer additional distinct benefits for both the grid and for data centers. First, self-supplying capacity can enable data centers to interconnect to the grid more quickly, potentially by years, than waiting for system upgrades, reducing the business impacts of time-to-power delays (Redwood Materials 2026; O'Dea 2026; Spector 2025). BTM batteries at a data center are also among the best-positioned tools to address load oscillation challenges from AI training behavior, and can maintain grid reliability via load smoothing in near-real time (NERC 2025b; Simonian 2025). Finally, data centers may also be able to use onsite BESS to earn revenue from demand response or other markets.

However, since these BTM batteries are not utility assets, they cannot generally serve other utility grid needs and do not offer utilities direct revenue opportunities. Perhaps obviously, BYOC requirements are also not an option for utilities impacted by data center-driven price spikes who do not anticipate new data center entrants in their own service territories. Requiring or incentivizing data centers to supply BTM BESS is also not mutually exclusive with additional procurement of FTM or distributed batteries.

A few of many examples of onsite BTM BESS deployment at data centers to enable speed-to-power, maintain grid reliability, and protect affordability for existing customers include:

- Aligned Data Centers, a data center developer, announced plans to deploy 31 MW / 62 MWh (2-hour) of onsite BESS to enable faster interconnection of its planned 100 MW data center in Oregon. The developer and utility both cited the agreement as a benefit for affordability and speed-to-power, noting the reduced need for new utility investments to accommodate the new load (Handshew and Benavides 2025; Walker 2025).

- Iron Mountain, another data center developer, announced plans in 2026 to install a 12 MW / 23 MWh BESS at a data center located in Edison, New Jersey. The BESS will be integrated with an existing 7.2 MW generation system. The developer claims the BESS will help improve regional grid reliability, contribute to demand charge reductions, and reduce the need for existing ratepayers to contribute to new system investments (Clancy 2026; Skidmore 2026).

3.3 Affordability and Reliability Contributions of Battery Energy Storage Compared to Capacity Alternatives

Utilities can meet forecasted capacity needs and resource adequacy targets through a combination of many different pathways, including traditional resource planning and procurement of transmission, distribution, and (depending on regulatory structure) standard or peaker generation assets in accordance with forecasted future load scenarios; purchasing additional market power, which can occur via long-term contracts or short-term spot market purchases; or deploying BESS as a non-wires alternative to traditional investments (U.S. Department of Energy 2024; Chew et al. 2018; Paulos 2021).

As previously noted, data centers can also provide their own capacity in a "BYOC" agreement, whether due to utility or regulatory requirements or in a voluntary effort to connect to the grid more quickly. BYOC scenarios may include BTM gas plants, BESS, or other combinations of generation and storage (O'Dea 2026; Black and Stedl 2025; Goncalves and Leonard 2026; Miller 2025). Another growing NWA approach is aggregation of customer-sited small-scale BESS and other resources, which can behave as a single asset (K. Brown 2023; Cohen et al.

2026). The following tables highlight and compare key considerations, potential ratepayer risks, and grid benefits of some of these pathways, including BESS and non-BESS capacity solutions.

Table 2 summarizes some key considerations, costs, and benefits for a range of different capacity solutions a utility may be able to pursue to meet a forecasted increase in peak demand, including the portfolio of “traditional” planning and procurement of generation, transmission, and distribution (T&D) infrastructure; additional wholesale market purchases; deploying utility-scale FTM energy storage; requiring data centers to bring their own gas or BESS capacity in order to interconnect; and aggregating small-scale BESS. These different solutions have different implications for potential ratepayer impacts, speed of deployment, revenue opportunities, and grid benefits.

For example, building new high-cost, long-lead-time infrastructure guarantees future grid reliability as peak demand increases, but imposes new costs to be recovered from ratepayers and exposes existing customers to the risk of high payments for underused assets if load growth does not materialize as forecasted (Acharya et al. 2025; Kavulla 2026). Spot market power purchases can help utilities quickly meet demand needs, but high prices can pose an affordability risk, as previously described in this report (Monitoring Analytics, LLC 2026; EIA 2026c).

Table 2: Key Considerations, Costs, and Benefits for Different Capacity Solutions for Utilities Planning for Large Load Growth

Approach	Summary	Ratepayer costs	Deployment timeline	Benefits	Risks and challenges	Needs or dependencies
Traditional Utility Resource Planning and Procurement	Utility builds new generation (depending on market structure), transmission, and distribution infrastructure as required to increase grid capacity to meet forecasted peak.	**High.** Capex for new gas plants, for example, is near $2,000/kW. System upgrades vary; new transmission lines or reconductoring can cost billions. Cost allocation approaches determine share of impacts to residential and other customers. Timeline mismatch and forecasting uncertainty raise stranded asset risk.	**Slow.** Procurement, permitting, construction, and interconnection timelines can be 5-10 years for utility-scale generation, whether built by a utility in a regulated market or an independent developer in a deregulated market. New transmission lines can take more than a decade to complete.	Guaranteed resource adequacy; utility can earn rate of return on capex.	Supply chain constraints increasing component prices; fuel price volatility; new generation assets may require transmission infrastructure, which is difficult and costly to build; long timelines mismatched with rapid load growth; high risk of stranded assets if data center load exits.	Resource needs based on load growth forecasts; impacted by forecast uncertainty.
Wholesale Power Market Purchases	Utility purchases power from wholesale market at market price to meet resource adequacy needs (assuming adequate transmission capacity). Can include long-term power purchase agreements (PPAs) and short-term market purchases.	**High and volatile.** Wholesale prices are increasing given supply constraints and rising demand (consider reported 76% increase in PJM capacity prices between Q1 2024 and Q1 2025).	**Fast**. Long-term PPAs require contract between utility and power producer. Short-term market purchases are quick by definition.	Utility does not need to procure own resources to supply needed capacity; smaller utilities can benefit from economies of scale; markets have typically lower costs of power production compared to self-supply.	Rising costs and increasing market volatility raise risks for ratepayers; uncertainty about future costs.	Prices and market structures vary by region, with some markets seeing higher price increases and greater volatility.
FTM BESS (Utility-Owned)	Utility deploys grid-scale battery storage at given capacity and duration (2- and 4-hour durations are common). Can be directly utility-owned or contracted.	**Moderate.** Capex for BESS (est. $1500/kW); system upgrades vary. Cost allocation approaches determine share of impacts to residential and other customers.	**Moderate.** Procurement, permitting, construction, interconnection. Timelines may be 2-4 years, potentially more if interconnection or other factors cause delays.	Can improve grid utilization; can defer costly investments with peak shaving; capital costs may be lower than traditional alternatives; market revenues offset some costs; utility can earn rate of return on capex; reliability benefits for grid.	If transmission-connected, utility-scale BESS subject to interconnection queue delays; revenue streams vary and are decreasing in some markets.	Regulatory and market structures impact use cases, participation opportunities; scale and duration of peak load impact viability.

Approach	Summary	Ratepayer costs	Deployment timeline	Benefits	Risks and challenges	Needs or dependencies
BTM BESS (Customer-Sited)	Data center funds, owns, and operates on-site energy storage. Acts as backup power, enables curtailment in exchange for faster interconnection, and offers reliability benefits.	**None.** Asset costs paid by developer.	**Fast.** 12–24 months; BTM projects bypass transmission interconnection bottlenecks.	Faster speed to power for customer than grid alone; provides backup power; avoids or reduces need for system upgrades; firm power source for customer for battery duration; reliability benefits for customer and grid.	Peak shaving value requires customer participation; utility likely does not earn market revenue; utility cannot use for other needs; value may be lost if data center exists.	Value to grid depends on tariff design, interconnection agreements, and battery size, and require customer to pursue grid interconnection.
BTM Gas Generation (Customer-sited)	On-site turbines for primary or backup power.	**None.** Asset costs paid by developer.	**Moderate to fast.** BTM gas generation can be operational in 1–3 years, depending on supply chain constraints and permitting; BTM projects bypass transmission interconnection bottlenecks.	Firm power source for customer; avoids or reduces need for system upgrades; faster speed to power for customer than grid alone.	Supply chain constraints and component cost volatility; risk to utility revenue and planning certainty if large load customers operate off-grid; utility cannot use for other needs; value may be lost if data center exits.	Considerations vary depending on whether customer is fully self-supplied or will also pursue grid interconnection.
Aggregated small-scale customer-sited BESS	Small residential/C&I batteries, potentially alongside other resources, aggregated to provide grid-scale capacity.	**Low.** Costs include program operation, customer incentives, and enabling technologies and software.	**Fast, especially if resources exist.** Programs can deploy and then scale as participants enroll.	Aggregations enable flexibility and improve grid utilization with few or no additional capital investments; fast deployment if resources and capabilities in place; BESS can provide local resilience benefits.	High operational complexity; may require deployment of enabling technologies and role of aggregator; resource adequacy benefits depend on scale and voluntary customer participation.	Effective deployment requires enabling technologies, aggregator; regulatory frameworks; tariff and incentive design.

Table 3 compares potential benefits of different BESS configurations and other more specific technologies that can be deployed to meet forecasted peak demand increases, including T&D investments, gas-powered peaker plants, diesel generators, and “BYOC” data center-sited BTM gas generation and BESS solutions. Key economic considerations include costs imposed on existing ratepayers, the risk of stranded assets if load growth does not materialize or data centers exit service earlier than anticipated, and what revenue streams are likely to be available. Benefits considered also include whether an asset can improve utilization of existing assets or enable flexibility for new large loads, which can help utilities increase the likelihood that large load additions can be rate-positive for existing customers. Finally, Table 3 also illustrates which technologies can efficiently provide reliability and resilience benefits, including smoothing of data center load oscillations and low voltage ride-through support (NERC 2026b, 2025a; Mohammadi et al. 2026; Mills and Olinsky-Paul 2025). Batteries are well-equipped to address these reliability challenges while also contributing to other goals, highlighting their value as a versatile and affordable asset under various configurations.

Detailed cost comparisons will vary by time, location, and other utility-specific considerations. This report does not recommend a specific pathway for any particular utility. Utilities facing different needs and challenges may weigh certain considerations differently. Instead, they are intended as a resource to highlight the ability of different solutions to achieve certain goals in the face of rapid and uncertain load growth driven by new data centers. Most utilities will likely pursue multiple solutions to meet resource adequacy needs as peak demand continues to increase.

Table 3: Benefits Comparison of Different Utility and BTM Capacity Solutions

Consideration	T&D Investments	Peaker plant (gas)	FTM diesel generators (Utility asset, as peaker)	FTM BESS (Utility asset)	Aggregated small customer-sited BESS	BTM gas generation (Customer-sited)	BTM diesel generators	BTM BESS (Customer-Sited)
Avoids new costs for other ratepayers?	No. Costs may be high.	No. High costs.	No, but lower risk of significant cost shifts than larger investments. Fuel prices can raise costs.	No, but lower risk of significant cost shifts than larger investments; does not incur fuel costs.	Yes	Yes; customer asset does not impact rates	Yes; customer asset does not impact rates	Yes; customer asset does not impact rates
Avoids stranded asset risk?	No. High costs and long lead times for large-scale infrastructure raise stranded asset risk.	No. High costs and long lead times for large-scale infrastructure raise stranded asset risk.	Smaller generators unlikely to be stranded	Relatively smaller systems unlikely to be stranded; BESS reduces risk of overbuild	Yes	Yes; customer asset does not impact rates	Yes; customer asset does not impact rates	Yes; customer asset does not impact rates
Opportunity to earn market revenues?	No	Yes, energy/capacity revenues	Yes, energy/capacity revenues	Yes, many revenue streams available: energy/capacity, ancillary services, arbitrage revenues; opportunities vary by market	Yes, for customers and aggregator; aggregators can bid into markets; potential energy/capacity, ancillary services, arbitrage	Potential energy/capacity revenues for customer, depending on size, interconnection, market structure	Potential energy/capacity revenues for customer, depending on size, interconnection, market structure	Maybe, for customer; potential energy/capacity, ancillary services, arbitrage; may require aggregator; depends on size, interconnection, market structure
Improves system utilization?	No; increases system peak	No; increases system peak	No; increases system peak	Yes; can provide peak shaving benefits	Yes; enables distributed load flexibility	Yes; all BTM power sources can enable DC load flexibility/ curtailment at peak	Yes; all BTM power sources can enable DC load flexibility/ curtailment at peak	Yes; all BTM power sources can enable DC load flexibility/ curtailment at peak

Consideration	T&D Investments	Peaker plant (gas)	FTM diesel generators (Utility asset, as peaker)	FTM BESS (Utility asset)	Aggregated small customer-sited BESS	BTM gas generation (Customer-sited)	BTM diesel generators	BTM BESS (Customer-Sited)
Enables data center load flexibility?	No	No	No	Not directly	Not directly, unless data center-sited BESS included in aggregation	Yes, if deployed as backup power; response in minutes	Yes, if deployed as backup power; quicker shifting than gas but slower than BESS	Yes; near instantaneous load shifting possible with enabling technologies
Offers smoothing for fluctuating AI loads?	No	No	No; effective smoothing requires near instantaneous response	Yes, can provide rapid shaving of AI load peaks	Not directly, unless data center-sited BESS included in aggregation	No	No	Yes, rapid shaving of AI load peaks
Offers voltage fault and low voltage ride-through capabilities?	No	No	No	Yes; can replace lost load by charging from grid	No	No	No	Yes; can avoid load losses or replace lost load by charging from grid if not in use as backup power
Offers resilience benefits during grid outages?	No	Can provide black start capabilities after outage	Can provide black start capabilities after outage	Can provide black start capabilities after outage	Insulates participating customers from grid outages	Insulates customer from grid outages	Insulates customer from grid outages	Insulates customer from grid outages

4.0 Conclusions

Battery energy storage has emerged as one of the most versatile tools available to utilities seeking to minimize the affordability and reliability risks posed by the rapid growth in large data center loads across the United States. The rise in AI data center deployments marks a sea change for a grid accustomed to more than a decade of nearly flat demand and is straining a system already beset by challenges deploying new grid capacity at scale. The supply constraints exacerbated by data center entry have already sharply increased wholesale power prices in some markets, and large loads' growing power demands risk exacerbating current electricity affordability challenges without effective policy, planning, and technology solutions.

Load growth can be rate-positive for utility customers, as it has been in the past. New demand can enable utilities to invest in upgrades that benefit many existing and future ratepayers while spreading those costs among a larger customer base. For this reason, growth has often been correlated with retail price decreases. However, the impact on the current era of large load growth on retail prices ultimately depends on whether new data center demand grows faster than the costs other ratepayers must pay to enable the grid to accommodate them. Multiple outcomes are possible. Prioritizing opportunities for data centers and other new loads to interconnect to the grid using existing assets where possible, while allocating the costs of any new needed infrastructure to large-load customers where needed, can make rate decreases more likely. However, the high costs and long timelines for new large-scale grid infrastructure, combined with uncertainty about the scale and longevity of the data center boom, raise risks of cost shifts if existing customers are asked to pay for assets that primarily benefit large load customers and that, at worst, risk becoming stranded assets. Meanwhile, if time-to-power delays cause many large loads to forgo grid interconnection altogether, a wave of data center grid defection would likely continue to drive up equipment and fuel expenses while denying utilities the benefit of large load contributions to their overall costs.

At a time when electricity rates have continued to rise faster than inflation and many Americans face difficulty paying their utility bills every month, identifying fast and effective solutions to control retail costs is of tantamount importance. These challenges are emphasized as more data centers are sited in rural areas. Small rural utilities and their customers, who often face high costs, reliability challenges, and aging infrastructure, stand to benefit significantly from the grid improvements that additional revenue from large loads could allow. However, these rural grid constraints, among other factors, also heighten the risk of cost shifts, underscoring the need for ratepayer protections.

Energy storage alone is not a panacea for the grid's current affordability challenges, but it offers many capabilities that can help protect ratepayers from data center-driven cost shifts, especially if deployment is paired with cost allocation reform, "bring your own capacity" requirements, and other regulatory solutions. Energy storage's primary affordability value in the context of large load growth is its ability to defer higher-cost system upgrades. While batteries cannot fully substitute for new generation, transmission, and distribution assets, BESS sized to meet incremental peak demand increases can enable higher utilization of existing resources outside of peak hours, allowing utilities to accommodate more load at lower average costs. Utility-scale or aggregated distributed energy storage can accommodate peak demand increases by charging when demand is low and discharging to the grid during the hours when additional capacity is needed. Batteries installed at data centers or other loads behind the meter, meanwhile, can enable those loads to curtail their grid usage during the hours of greatest grid strain. This deferral value also serves as a valuable hedge against the risk that ratepayers will be left financially responsible for stranded assets if data center load does not materialize or exits earlier than forecasted.

While there is little evidence that data centers have been responsible for widespread increases in retail electricity costs to date, they have driven up wholesale energy and capacity prices as forecasted demand has outstripped available supply. As supply chain challenges, permitting delays, and interconnection queue backlogs continue to limit the pace of new capacity additions, this trend is likely to increase. Utilities that are more reliant on wholesale power market purchases are more likely to see customers' retail prices increase as a result, particularly if they are impacted by wholesale demand charges. This risk is especially pronounced for smaller consumer-owned utilities. Energy storage's ability to "shave" system peaks and reduce the need for expensive spot market purchases during peak demand periods can help insulate these utilities' ratepayers from the impacts of wholesale market volatility. Additionally, utilities can benefit from deploying BESS for peak shaving even if they do not have new data center customers entering their service territory but are nonetheless impacted by regional price trends driven by widespread load growth. Finally, BESS can capably mitigate some of the risks that AI data center loads pose to the reliability of the grid, including by smoothing rapid oscillations in demand and preventing or mitigating massive load losses from relatively minor voltage faults. Batteries can provide reliability benefits in addition to other services, emphasizing their value as a versatile, affordable solution for many emergent challenges at once.

It is important to note that barriers exist to deploying energy storage at scale and maximizing its potential grid value. Energy storage technologies, like many other energy projects, face supply chain, permitting, and interconnection challenges. Market compensation for storage's energy, capacity, and ancillary services contributions varies, and systems' upfront costs remain a barrier, even as capital costs continue to decrease. The very qualities that make BESS an affordability and reliability asset, particularly its ability to interchangeably behave as generation or load and perform a variety of functions depending on grid needs, have challenged regulatory paradigms designed for less flexible technologies.

Regardless, energy storage—sometimes aptly described as a "Swiss Army knife" for the grid, has proven its ability to play many important roles on a constantly evolving grid. Many utilities, regulators, ratepayers, and data center developers nationwide have already deployed energy storage to reduce costs, speed up interconnection timelines, and contribute to reliability and resilience goals. Energy storage's versatility will continue to be key to its value as an affordability solution in the face of current load growth challenges as well as many more emerging grid needs.

References

Acharya, Samrat, Eran Schweitzer, Devyn W. Powell, and Aaqib Peerzada. 2025. *Measuring the Cost of Potential Stranded Assets from Speculative Large Load Interconnection Requests*. PNNL-SA-217207. Pacific Northwest National Laboratory.

AEP Ohio (American Electric Power). 2025. “AEP Ohio Proposal on Data Centers to Protect Ohio Consumers Adopted by PUCO.” July 9. https://www.aep.com/news/stories/view/10327/.

Anderson, Erik, Prathit Dave, Adrienne Rackley, and Devyn W. Powell. 2025. *Policy and Cost Allocation Considerations for Large Electric Load Interconnections*. PNNL-38455. Pacific Northwest National Laboratory. https://www.osti.gov/biblio/3364473.

Ansolabehere, Stephen, Jason Beckfield, Hannah Dobie, et al. 2024. *Crossed Wires: A Salata Institute-Roosevelt Project Study of the Development of High-Voltage Transmission Lines in the United States*. Salata Institute for Climate and Sustainability, Harvard University.

Aurora Energy Research. 2025. *Battery Energy Storage Impact and Benefits Assessments in MISO*. Aurora Energy Research Ltd. https://go.auroraer.com/l/885013/2025-07-29/pny4d/885013/1753797537FU0B9Zvy/Aurora_ACP_BESS_Impact_Analysis_MISO_Final_Report_07.18.2025.pdf.

Bakalar, Sophie (Venturebeat). 2025. “Phantom Data Centers: What They Are (or Aren’t) and Why They’re Hampering the True Promise of AI.” January 4. https://venturebeat.com/ai/phantom-data-centers-what-they-are-or-arent-and-why-theyre-hampering-the-true-promise-of-ai.

Benson, Thomas S., Juliet Homer, Jason Eisdorfer, Suprajha Nagaraja Sudhakar, James Gibson, and Jess Barcco. 2026. “Regulatory Approaches for Aligning AI Data Center Growth With Residential Energy Affordability.” *Pacific Northwest National Laboratory* Forthcoming.

Bertolacini, Molly, Shana Ramirez, Megan Ahern, Anna Clark, and Kush Patel. 2026. *An Empirical Analysis of Data Center Grid Utilization, Cost-of-Service and Revenue Contributions*. Energy and Environmental Economics, Inc. (E3). https://www.ethree.com/wp-content/uploads/2026/06/E3_Large-Load-Economics_June-2026.pdf.

Besuner, Phil, Energy Futures Group, and Halcyon. 2025. *The New Reality of Power Generation: An Analysis of Increasing Gas Turbine Costs in the U.S.* GridLab, Energy Futures Group, and Halcyon. https://gridlab.org/portfolio-item/gas-tubine-cost-report/.

Black, David, and Matt Stedl. 2025. “Key Considerations for Co-Located Battery Storage.” *Solar Power World*, May 29. https://www.solarpowerworldonline.com/2025/05/key-considerations-for-co-located-battery-storage/.

BLS (Bureau of Labor Statistics). 2026. “Consumer Price Index (CPI) Databases.” May. https://www.bls.gov/cpi/data.htm.

Bonner, April. 2025. “The Majority of Utility-Scale Batteries Were Used for Arbitrage in 2024 – US EIA Survey Finds.” *Energy-Storage.News*, September 23. https://www.energy-storage.news/the-majority-of-utility-scale-batteries-were-used-for-arbitrage-in-2024-us-eia-survey-finds/.

Brancucci, Carlo, Dylan Cutler, Emma Elgqvist, et al. 2025. *Flexible Data Centers: A Faster, More Affordable Path to Power*. Camus, encoord, and Princeton ZERO Lab. https://www.camus.energy/flexible-data-center-report.

Brown, Kim (Brattle). 2023. “Virtual Power Plants (VPPs) Could Save US Utilities $15-$35 Billion in Capacity Investment Over 10 Years.” April 28. https://www.brattle.com/insights-events/publications/real-reliability-the-value-of-virtual-power/.

Brown, William, Henry Chao, Arnold Schuff, and Steven Wang. 2023. *Storage as Transmission Asset Market Study*. New York Battery and Energy Storage Technology (NY-BEST) Consortium. https://cdn.ymaws.com/ny-best.org/resource/resmgr/reports/SATA_White_Paper_Final_01092.pdf.

CAISO. 2025. *2024 Special Report on Battery Storage*. California Independent System Operator. https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf.

Campbell, Ben, and Seth Miller (E Source). 2026. “Why Are Batteries Becoming Essential for AI Data Center Load Management?” March 6. https://www.esource.com/white-paper/why-are-batteries-becoming-essential-ai-data-center-load-management.

CFC (CFC Solutions Cooperative News). 2026. “Exploring Virtual Power Plants: Key Considerations for Leaders.” March 2. https://www.nrucfc.coop/content/solutions/en/stories/energy-tech/exploring-virtual-power-plants--key-considerations-for-leaders.html.

Chew, Brenda, Erika H. Myers, Tigers Adolf, and Ed Thomas. 2018. *Non-Wires Alternatives: Case Studies from Leading U.S. Projects*. Smart Electric Power Alliance, Peak Load Management Alliance, and E4TheFuture. https://e4thefuture.org/wp-content/uploads/2018/11/2018-Non-Wires-Alternatives-Report_FINAL.pdf.

Clancy, Heather. 2026. “Iron Mountain’s Data Center Battery Project.” *Trellis*, March 26. https://trellis.net/article/iron-mountain-data-center-battery-project/.

Cleanview (Cleanview). 2026. “US Data Center Map — Project List & Tracker.” May. https://cleanview.co/data-centers/us.

Cohen, Jesse, Mark Dyson, and Lauren Shwisberg. 2026. “How VPPs Can Help Data Centers Connect to the Grid Faster.” *Utility Dive*, January 8. https://www.utilitydive.com/news/vpp-virtual-power-plant-data-centers-RMI/805605/.

Cole, Wesley, Vignesh Ramasamy, and Merve Turan. 2025. *Cost Projections for Utility-Scale Battery Storage: 2025 Update*. https://docs.nlr.gov/docs/fy25osti/93281.pdf.

Convergent Energy and Power. 2024. “How Energy Storage Insulates Utilities against Rising Electricity Costs.” *Utility Dive*, April 1. https://www.utilitydive.com/spons/how-energy-storage-insulates-utilities-against-rising-electricity-costs/711509/.

Cooke, Alan, Rebecca O’Neil, and Jeremy Twitchell. 2019. *Energy Storage in Integrated Resource Plans*. PNNL--28627, 1566781. https://doi.org/10.2172/1566781.

Data Cent. Map (Data Center Map). 2026. “Data Center Map.” https://www.datacentermap.com/.

Datacenters.com (Datacenters.Com). 2026. “District Of Columbia Data Center Locations.” June. https://www.datacenters.com/locations/united-states/district-of-columbia.

Davis, Ron. 2009. *Calculating the Revenue Requirement*. National Association of Regulatory Utility Commissioners. https://pubs.naruc.org/pub.cfm?id=5376DE70-2354-D714-51BA-736C233E4185.

DCPSC (District of Columbia Public Service Commission). 2026. “Electricity Standard Offer Service (SOS) Rates.” May. https://dcpsc.org/Utility-Information/Electric/Electricity-Standard-Offer-Service-(SOS)-Rates.aspx.

Din, Jade. 2026. “Peak Shaving Explained: Solar, BESS and Reduced Costs.” *Elum*, May 11. https://elum-energy.com/blog/peak-shaving-solar-energy-storage-methods-to-reduce-peak-load/.

Dominion Energy. 2024. *SCC Directed 2024 IRP Supplement*. PUR-2024-00184. Virginia State Corporation Commission. https://www.scc.virginia.gov/docketsearch/DOCS/82l101!.PDF.

Donohoo-Vallett, Paul, Ben King, Hannah Kolus, and Anna van Brummen. 2026. *Caught in the Current: Historical and Prospective Drivers of Changes in US Electricity Prices*. Rhodium Group. https://rhg.com/research/us-electricity-prices-drivers/.

Dueñas, Sergio, Eliasid Animas, Jaide Lin, Todd Olinsky-Paul, and Olivia Tym. 2024. *Battery Storage for Fossil-Fueled Peaker Plant Replacement: A Maine Case Study*. Clean Energy States Alliance. https://www.cesa.org/resource-library/resource/battery-storage-peaker-plant-replacement-maine/.

Dukosi. 2025. “Battery Energy Storage Systems in AI Data Center Design.” *Dukosi Ltd*, December 15. https://www.dukosi.com/app/uploads/2025/12/BESS_in_AI_Data_Center_Design_BLOG_December_2025.pdf.

EIA (U.S. Energy Information Administration (EIA)). 2012. “Electric Generator Dispatch Depends on System Demand and the Relative Cost of Operation.” August 17. https://www.eia.gov/todayinenergy/detail.php?id=7590.

EIA (U.S. Energy Information Administration (EIA)). 2025a. “After More than a Decade of Little Change, U.S. Electricity Consumption Is Rising Again.” May 13. https://www.eia.gov/todayinenergy/detail.php?id=65264.

EIA (U.S. Energy Information Administration). 2025b. “U.S. Electricity Prices Continue Steady Increase.” May 14. https://www.eia.gov/todayinenergy/detail.php?id=65284.

EIA (Energy Information Administration (EIA)). 2026a. “2024 Residential Utility Disconnections Report.” April 14. https://www.eia.gov/analysis/requests/residential/utility/.

EIA (U.S. Energy Information Administration (EIA)). 2026b. “Electric Power Monthly: Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector, by State, March 2026 and 2025.” March. https://www.eia.gov/electricity/monthly/epm_table_grapher.php.

EIA (Energy Information Administration (EIA)). 2026c. “Regional Wholesale Markets: March 2026.” May 22. https://www.eia.gov/electricity/monthly/update/wholesale-markets.php.

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

Ewing, Jackson. 2026. “The Grid’s Choice Is between Large Load Flexibility versus Defection.” *Latitude Media*, June 18. https://www.latitudemedia.com/news/the-grids-choice-is-between-large-load-flexibility-versus-defection/.

Fagan, Marie, and Victor Chung. 2025. *Uncertainty and Upward Bias Are Inherent in Data Center Electricity Demand Projections*. London Economics International LLC for the Southern Environmental Law Center. https://www.selc.org/wp-content/uploads/2025/07/LEI-Data-Center-Final-Report-07072025-2.pdf.

FlexGen (FlexGen). 2025. “How Battery Storage Can Solve the 4-Hour Peak Demand Problem.” March 17. https://www.flexgen.com/resources/blog/how-battery-storage-can-solve-4-hour-peak-demand-problem.

Georgia Power (Georgia Power). 2026. “Georgia PSC Approves Plan to Lower Overall Rates, Deliver Annual Savings of $50 per Year for Georgia Power Residential Customers.” May 28. https://www.georgiapower.com/news-hub/press-releases/georgia-psc-approves-plan-to-lower-overall-rates.html.

Giacobone, Bianca. 2025. “Phantom Data Centers Are Flooding the Load Queue.” *Latitude Media*, March 26. https://www.latitudemedia.com/news/phantom-data-centers-are-flooding-the-load-queue/.

Gombar, Vandana. 2026. “US Data Center Builder Goes Off-Grid to Speed Deployments.” *BloombergNEF*, February 27. https://about.bnef.com/insights/commodities/us-data-center-builder-goes-off-grid-to-speed-deployments/.

Goncalves, Christopher, and Hans Leonard. 2026. “Who Pays to Power AI Data Centers? Comparing BYOG and Backstop Capacity Procurement.” *Thinkset Magazine*. https://www.thinkbrg.com/thinkset/who-pays-to-power-ai-data-centers-comparing-byog-and-backstop-capacity-procurement/.

Gorman, Will, Joseph Rand, Julia Matevosyan, and Fredrich Kahrl. 2024. *Transmission Interconnection Roadmap*. U.S. Department of Energy.

https://www.energy.gov/sites/default/files/2024-04/i2X%20Transmission%20Interconnection%20Roadmap.pdf.

Green, Shelby. 2026. "Federal Data Shows over 13 Million Electric Shutoffs as Industry Posts Record Profits." *Energy and Policy Institute*, April 20. https://energyandpolicy.org/thirteen-million-electric-shutoffs-as-industry-posts-record-profits/.

Halper, Evan. 2026. "Data Centers Are Getting Off-Grid Power Plants." *Washington Post*, February 19. https://www.washingtonpost.com/business/2026/02/19/data-centers-power-grid-ai/.

Handshew, Jennifer, and Liz Benavides. 2025. "Aligned and Calibrant to Deploy First-of-Its-Kind On-Site Battery Storage Project to Unlock Utility Power for Data Centers." *Aligned Data Centers*, October 22. https://aligneddc.com/press-release/aligned-and-calibrant-to-deploy-first-of-its-kind-energy-solution/.

Heynes, George. 2024. "Arizona's Biggest Battery Storage System Goes Online to Feed Meta Data Centre Demand." *Energy-Storage.News*, October 14. https://www.energy-storage.news/arizonas-biggest-battery-storage-system-goes-online-to-feed-meta-data-centre-demand/.

Hill, Michael. 2025. "Fears of Massive Battery Fires Spark Local Opposition to Energy Storage Projects." *Insurance Journal*, October 6. https://www.insurancejournal.com/news/national/2025/10/06/842596.htm.

Hledik, Ryan, and Long Lam. 2026. *Retail Electricity Price Trends and Drivers: Data Update−2026 Edition*. Lawrence Berkeley National Laboratory and Brattle Group. https://emp.lbl.gov/sites/default/files/2026-03/Retail%20Price%20Trends_2026%20edition.pdf.

Hledik, Ryan, Long Lam, and Kate Peters. 2026. *The Untapped Grid*. Brattle Group. https://www.brattle.com/the-untapped-grid/.

Hledik, Ryan, and Kate Peters. 2023. *Real Reliability: The Value of Virtual Power*. Brattle Group. https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power_5.3.2023.pdf.

Inaolaji, Adedoyin, Xuan Wu, Rajarshi Roychowdhury, and Raiford Smith. 2024. "Optimal Allocation of Battery Energy Storage Systems for Peak Shaving and Reliability Enhancement in Distribution Systems." *Journal of Energy Storage* 95 (August): 112305. https://doi.org/10.1016/j.est.2024.112305.

Jamison, Mark A. 2007. "Rate of Return: Regulation." In *Encyclopedia of Energy Engineering and Technology*, vol. 3. University of Florida Public Utility Research Center. https://bear.warrington.ufl.edu/centers/purc/docs/papers/0528_jamison_rate_of_return.pdf.

Johnson, Shari. 2025. "GVEC Becomes First Tesla Utility Partner in Texas." *GVEC*, March 3. https://www.gvec.org/gvec-becomes-first-tesla-utility-partner-in-texas/.

Kaps, Christian, and Rachel Layne (Harvard Business School). 2026. “Falling Battery Storage Costs Are Quietly Reshaping Electricity Markets.” January 23. https://www.library.hbs.edu/working-knowledge/falling-battery-storage-costs-are-quietly-reshaping-electricity-markets.

Kavulla, Travis. 2026. “How Will Data Centers Pay for Power?” *American Affairs Journal*, May 20. https://americanaffairsjournal.org/2026/05/how-will-data-centers-pay-for-power/.

Kerby, Jessica R. 2025. *Energy Storage Best Practices Factsheet*. PNNL-SA-214303. Pacific Northwest National Laboratory (PNNL). https://www.osti.gov/biblio/3013041.

Kerstein, Helen. 2025. *Assessing California’s Climate Policies—Residential Electricity Rates in California*. California Legislative Analyst’s Office. https://lao.ca.gov/Publications/Report/4950.

Khaldi, Mona (Voltus). 2026. “Voltus and Google Announce Bring Your Own Capacity Agreement.” June 2. https://www.voltus.co/press/voltus-google-bring-your-own-capacity-pjm.

Kotwis, Sarah Toth, Ashtin Massie, Abigail Araya, and Drew Beyer. 2025. “Batteries: The Workhorse of an Affordable, Reliable Grid - RMI.” *RMI*, September 10. https://rmi.org/batteries-the-workhorse-of-an-affordable-reliable-grid/.

KPP. 2022. *Kansas Power Pool Independent Auditor’s Reports and Financial Statements*. Kansas Power Pool. https://www.kpp.energy/wp-content/uploads/2024/10/2022-kpp-audit.pdf.

Kuuskvere, Cara, and Weston Dengler. 2024. “The Aging US Power Grid: Navigating Toward Modernization.” *Smart Electric Power Alliance*, September 19. https://sepapower.org/knowledge/the-aging-us-power-grid-navigating-toward-modernization/.

Lam, Long, Ryan Hledik, and Natalie Northrup. 2026. *Impacts of Large Loads on Electricity Rates: A Primer*. Energy Systems Integration Group. https://www.esig.energy/wp-content/uploads/2026/05/ESIG-Large-Load-Rate-Impacts-primer-WP-2026.pdf.

Latitude Intelligence. 2026. *The Terms of Power: Inside the New Utility Rates for Data Centers*. Latitude Intelligence. https://44409563.fs1.hubspotusercontent-na1.net/hubfs/44409563/Terms%20of%20Power_White%20Paper_260316.pdf?__hstc=128018835.64f8fb02dcaa5a8dd25a54832b2614fe.1780702183673.1780702183673.1780702183673.1&__hssc=128018835.1.1780702183673.

Lawson, Ashley J., Martin Offutt, Natalie Ortiz, and Ling Zhu. 2026. *Data Centers and Their Energy Consumption: Frequently Asked Questions*. No. R48646. Congressional Research Service. https://www.congress.gov/crs-product/R48646.

Lazar, Jim. 2015. “Dividing the Pie: Cost Allocation, the First Step In the Rate Design Process.” Appendix A. *Smart Rate Design for a Smart Future*, August 31. https://www.raponline.org/wp-content/uploads/2023/09/appendix-a-smart-rate-design-2015-aug-31.pdf.

Lazard. 2025. *Lazard Levelized Cost of Energy+*. Lazard. https://www.lazard.com/media/5tlbhyla/lazards-lcoeplus-june-2025-_vf.pdf.

Macmillan, Madeline, Kyle Wilson, Sunhee Baik, Juan Pablo Carvallo, Anamika Dubey, and Christine A. Holland. 2023. “Shedding Light on the Economic Costs of Long-Duration Power Outages: A Review of Resilience Assessment Methods and Strategies.” *Energy Research & Social Science* 99 (May): 103055. https://doi.org/10.1016/j.erss.2023.103055.

Marshall, Christa. 2026. “Data Centers Drive 76% Surge in PJM Power Prices.” *E&E News by POLITICO*, May 15. https://www.eenews.net/articles/data-centers-drive-76-surge-in-pjm-power-prices/.

Martin, Eliza, and Ari Peskoe. 2025. *Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech’s Power*. Harvard Law School Environmental & Energy Law Program. https://eelp.law.harvard.edu/wp-content/uploads/2025/03/Harvard-ELI-Extracting-Profits-from-the-Public.pdf.

Martucci, Brian. 2026a. “EPB of Chattanooga Deploys Battery-Based Microgrids for Savings, Resilience.” *Utility Dive*, March 11. https://www.utilitydive.com/news/epb-of-chattanooga-deploys-battery-based-microgrids-for-savings-resilience/814476/.

Martucci, Brian. 2026b. “Not-for-Profit Utilities Turn to Energy Storage as Data Centers Drive Cost, Reliability Concerns.” *Utility Dive*, June 9. https://www.utilitydive.com/news/not-for-profit-utilities-turn-to-energy-storage-as-data-centers-drive-cost/822370/.

Martucci, Brian. 2026c. “Virginia Public Power Providers Embrace Megawatt-Scale, Distribution-Connected Batteries.” *Utility Dive*, April 21. https://www.utilitydive.com/news/virginia-public-power-providers-embrace-megawatt-scale-distribution-connec/818082/.

Miller, Marguerite. 2025. “PJM CIFP Analysis: Data Center Interconnection & BYOG Strategy.” *ECM Enterprises, LLC*, December 9. https://ecmcompany.com/pjm-cifp-analysis-data-center-interconnection-byog-strategy/.

Mills, Nate, and Todd Olinsky-Paul. 2025. *Location, Location, Location: An Economic Comparison of Large-Scale Batteries Installed in Front of vs. behind the Meter in Massachusetts*. American Microgrid Solutions for Clean Energy Group. https://www.cleanegroup.org/wp-content/uploads/CVEC-Report-Massachusetts.pdf.

Mirletz, Brian, Laura Vimmerstedt, Tyler Stehly, et al. 2024. “2024 Annual Technology Baseline (ATB) Cost and Performance Data for Electricity Generation Technologies.” DOE Open Energy Data Initiative (OEDI); National Renewable Energy Laboratory (NREL). 9 files. https://doi.org/10.25984/2377191.

MISO. 2025. “Long Term Resource Adequacy & Interconnection Queue Update.” Midcontinent System Operator. System Planning Committee of the Board of Directors, September 16. https://cdn.misoenergy.org/06_2025-09-16_SPC_Open_Long%20Term%20Resource%20Adequacy%20%20Interconnection%20Queue%20Update_FINAL717559.pdf.

Modo Energy (Modo Energy). 2026. "SPP's Ancillary Services Explained: Why It Matters for Batteries." April 14. https://modoenergy.com/research/en/spp-ancillary-services-explanation-regulation-reserves-spinning-supplemental-uncertainty-ramp-batteries.

Mohammadi, Sina, Wayne Wang, Marcus Chen I. Wada, et al. 2026. "Grid Integration of AI Data Centers: A Critical Review of Energy Storage Solutions." arXiv:2603.00415. Version 1. Preprint, arXiv, February 28. https://doi.org/10.48550/arXiv.2603.00415.

Moncheur de Rieudotte, Malcolm P., and Jessica R. Kerby. 2025. *Typical Use Cases for Energy Storage in Rural Areas*. PNNL--37841. Pacific Northwest National Laboratory (PNNL), Richland, WA (United States). https://doi.org/10.2172/3012466.

Monitoring Analytics, LLC. 2026. *2026 Quarterly State of the Market Report for PJM*. PJM. https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2026/2026q1-som-pjm.pdf.

MPSC (Michigan Public Service Commission). 2026. "MPSC Goes Big on Batteries, Approving Six Energy Storage Contracts Totaling 1,332 Megawatts." March 27. https://www.michigan.gov/mpsc/commission/news-releases/2026/03/27/mpsc-goes-big-on-batteries.

Nadel, Steven. 2025. "Data Center Efficiency and Load Flexibility Can Reduce Power Grid Strain and Costs." *ACEEE*, October 7. https://www.aceee.org/blog-post/2025/10/data-center-efficiency-and-load-flexibility-can-reduce-power-grid-strain-and.

NERC. 2025a. *Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions*. North American Electric Reliability Corporation. https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf.

NERC. 2025b. *NERC Large Loads Task Force Meeting and Workshop*. North American Electric Reliability Corporation. https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/llwg/lltf_april_meeting__technical_workshop_presentations_.pdf.

NERC. 2026a. *Long Term Reliability Assessment*. North American Electric Reliability Corporation. https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

NERC. 2026b. *Risk Mitigation for Emerging Large Loads*. North American Electric Reliability Corporation. https://www.nerc.com/globalassets/our-work/guidelines/reliability/RG_Risk-Mitigation-For-Emerging-Large-Loads.pdf.

NERC Large Loads Task Force. 2025. *Characteristics and Risks of Emerging Large Loads*. North American Electric Reliability Corporation. https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper%20Characteristics%20and%20Risks%20of%20Emerging%20Large%20Loads.pdf.

Nguyen, Quan H., Xue Lyu, Meng Zhao, Jessica R. Kerby, Laurentiu D. Marinovici, and Diane A. Baldwin. 2025. *Optimal Control for Fast Frequency Response and Black-Start Using Embedded Storages with Grid-Forming Control*. PNNL--35705. Pacific Northwest National Laboratory (PNNL), Richland, WA (United States). https://doi.org/10.2172/2569616.

Nolette, Vincent. 2026. "Data Center Regulation: What Local Governments Should Know about Large-Load Tariffs and Clean Transition Tariffs." *Climate Law Blog*, June 2. https://blogs.law.columbia.edu/climatechange/2026/06/02/data-center-regulation-what-local-governments-should-know-about-large-load-tariffs-and-clean-transition-tariffs/.

Norris, Tyler H., Tim Profeta, Dalia Patino-Echeverri, and Adam Cowie-Haskell. 2025. *Rethinking Load Growth: Assessing the Potential of Large Flexible Loads in US Power Systems*. NI R 25-01. Duke Nicholas Institute for Energy, Environment and Sustainability. https://nicholasinstitute.duke.edu/sites/default/files/publications/rethinking-load-growth.pdf.

O'Dea, Blathnaid. 2026. "How On-Site Batteries Are Fast-Tracking Data Center Grid Connections." *PV Magazine*, March 18. https://pv-magazine-usa.com/2026/03/18/how-on-site-batteries-are-fast-tracking-data-center-grid-connections/.

Oikonomou, Konstantinos, Bharat Vyakaranam, Tony Nguyen, et al. 2024. *Western Interconnection Baseline Study*. PNNL-36452. Pacific Northwest National Laboratory. https://doi.org/10.2172/2440740.

Olinsky-Paul, Todd. 2026. "Virtual Power Plant Programs Summary Table." *Clean Energy States Alliance*, February. https://www.cesa.org/projects/energy-storage-policy-for-states/virtual-power-plant-programs-summary-table/.

Orelowitz, Aaron (Modo Energy). 2026. "Data Centers Define PJM's 2046 Load Forecast - Research." February 27. https://modoenergy.com/research/en/pjm-load-forecast-data-centers-2046.

Paccou, Remi, and Fons Wijnhoven. 2025. *Powering Sustainable AI in the United States*. Schneider Electric. https://download.schneider-electric.com/files?p_enDocType=Thought_Leadership_Article&p_Doc_Ref=TLA_SRI_Sustainable_AI_US.

Pacifico Energy (Pacifico Energy). 2026. "GW Ranch | Off-Grid Power Generation." https://www.pacificoenergy.com/gw-ranch.

Pahl, Mothusi. 2026. *The Rural Grid Squeeze*. Alliance for Innovation and Infrastructure. https://www.aii.org/wp-content/uploads/2026/06/The-Rural-Grid-Squeeze.-HL.pdf.

Paulos, Bentham. 2021. *How Wholesale Power Markets Work*. Clean Energy States Alliance. https://www.cesa.org/wp-content/uploads/How-Wholesale-Power-Markets-Work.pdf.

Perez, Alyssa, Sarah Wang, and Lauren Shwisberg. 2025. "Large Energy Users Want Power. Here's How to Protect Other Ratepayers from the Costs." *RMI*, November 7. https://rmi.org/large-energy-users-want-power-heres-how-to-protect-other-ratepayers-from-the-costs/.

Peterson, Cally, and Cathy Cash (North Dakota Living). 2026. "Data Centers Eye Rural America." April 2. https://www.ndliving.com/data-centers-eye-rural-america.

PJM. 2026. *2026 PJM Load Forecast Report*. PJM. https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2026-load-report.pdf.

Powell, Devyn W., Shahnawaz A. Siddiqui, Jessica R. Kerby, Alan L. Cooke, Sara E. Murphy, and Thomas S. Benson. 2025. *A Framework for Streamlining Large Load Interconnection*. PNNL-38441. Pacific Northwest National Laboratory. https://doi.org/10.2172/3364477.

Powell, Devyn W., and Jeremy B. Twitchell. 2026. *Principles and Options for Designing Battery Energy Storage Zoning Ordinances*. PNNL-37956. Pacific Northwest National Laboratory (PNNL), Richland, WA (United States). https://doi.org/10.2172/3013849.

Powell, Devyn W., Jeremy Twitchell, and Prathit Dave. 2024. *Tracking Local Moratoria and Other Key Considerations for Battery Energy Storage Siting*. Pacific Northwest National Laboratory. https://www.sandia.gov/app/uploads/sites/82/2024/08/PR2024_404_Powell_Devyn_Policy.pdf.

PowerLines. 2026. “New PowerLines-Ipsos Poll Finds a Majority of Americans Report Rising Utility Bills as Utilities File $9.4 Billion in Rate Increase Requests in Q1 2026.” *PowerLines*, May 19. https://powerlines.org/new-powerlines-ipsos-poll-finds-a-majority-of-americans-report-rising-utility-bills-as-utilities-file-9-4-billion-in-rate-increase-requests-in-q1-2026/.

Quint, Ryan, Jiecheng Zhao, and Kyle Thomas. 2025. *An Assessment of Large Load Interconnection Risks in the Western Interconnection*. Western Electric Coordinating Council. https://www.rtoinsider.com/wp-content/uploads/2025/03/Report_WECC-Large-Loads-Risk-Assessment-4.pdf.

Rand, Joseph, Nick Manderlink, Steven Zhang, et al. 2024. *Queued Up: 2025 Edition, Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2024*. Lawrence Berkeley National Laboratory. https://emp.lbl.gov/queues.

Rawlings, William (Modo Energy). 2026. “MISO Ancillary Services: A Beginner’s Guide.” February 4. https://modoenergy.com/research/en/miso-ancillary-services-bess-regulation-.

Redwood Materials (Redwood Materials). 2026. “Data Center Energy Storage: Solving Speed to Power for AI Factories.” April 1. https://www.redwoodmaterials.com/resources/data-center-energy-storage-solving-speed-to-power-for-ai-factories/.

Ribeiro, Henrique. 2026. “BESS as a ‘Swiss Army Knife’ for Data Centers.” *PV Magazine*, June 22. https://prometheus.org/2026/06/22/bess-as-a-swiss-army-knife-for-data-centers/.

Rissman, Jeffrey, and Eric Gimon. 2026. “Behind-the-Meter Data Center Gas Plants Will Raise US Energy Bills.” *Utility Dive*, June 8. https://www.utilitydive.com/news/data-centers-raise-energy-bills-not-for-reason-you-think/822205/.

Robinson, J., Tom DiChristopher, and Kassia Micek (S&P Global Market Intelligence). 2021. “Natural Gas in Transition: Grid-Balancing Tactics in Flux as Battery Costs Fall.” June 8. https://www.spglobal.com/market-intelligence/en/news-insights/articles/2021/6/natural-gas-in-transition-grid-balancing-tactics-in-flux-as-battery-costs-fall-64822077.

Rochas, Anna Flávia (Reuters Events). 2026. “Power Developers Adapt Gas Turbine Strategies to Mitigate Tight Supply.” March 2. https://www.reutersevents.com/renewables/solar-pv/power-developers-adapt-gas-turbine-strategies-mitigate-tight-supply.

Ross, Lauren, Ariel Drehobl, and Brian Stickles. 2018. *The High Cost of Energy in Rural America:* American Council for an Energy-Efficient Economy. https://www.aceee.org/sites/default/files/publications/researchreports/u1806.pdf.

Ryu, Angela, and Shon R. Hiatt. 2026. *Data Center Entry and U.S. Electricity Prices: From the Wholesale Market to the Power Bill*. Energy Brief. USC Marshall Zage Business of Energy Initiative. https://drive.google.com/file/d/1IWolyGYxOv5ENI3frcRU8U0Mge_fbWUr/view.

Sakib, Sadnan, Md. Biplob Hossain, Muhammad Ahsan Zamee, M. J. Hossain, and Md. Ahasan Habib. 2025. “Role of Battery Energy Storage Systems: A Comprehensive Review on Renewable Energy Zones Integration in Weak Transmission Networks.” *Journal of Energy Storage* 128 (August): 117223. https://doi.org/10.1016/j.est.2025.117223.

Seets, Skyler, and Kaitlyn Radde. 2026. “Most New Data Centers in the U.S. Are Coming to Rural Areas.” *Pew Research Center*, April 13. https://www.pewresearch.org/short-reads/2026/04/13/most-new-data-centers-in-the-us-are-coming-to-rural-areas/.

SEPA (Smart Electric Power Alliance and North Carolina Clean Energy Technology Center). 2026. “Database of Emerging Large-Load Tariffs (DELTa).” March 31. https://sepapower.org/large-load-tariffs-database/.

Shah, Jigar, and Arnab Pal. 2026. *Grid Growth, Utilization, and Affordability: A Playbook for States*. Deploy Action. https://static1.squarespace.com/static/69a1d07c47b5247cf0f92b36/t/69a76859511ebe6f1a383de3/1772578905994/Grid+Affordability+-+State+Playbook+-+Final.pdf.

Simonian, Amanda. 2025. “Data Center Volatility, Batteries and the Electric Grid’s New Reality.” *Utility Dive*, November 14. https://www.utilitydive.com/news/data-center-volatility-flow-batteries-grid/805197/.

Singh, Shailendra, Santosh Veda, S. P. Singh, and Murali Baggu. 2018. “Maximizing the Benefits of Volt/VAR Optimization in the Presence of Community Energy Storage.” *2018 IEEE International Conference on Power Electronics, Drives and Energy Systems (PEDES)*, December, 1–6. https://doi.org/10.1109/PEDES.2018.8707524.

Skidmore, Zachary (Data Center Dynamics). 2026. “Iron Mountain Partners with Energy Storage Firm Calibrant to Deploy 23MWh BESS Unit at New Jersey Data Center.” March 16. https://www.datacenterdynamics.com/en/news/iron-mountain-partners-with-energy-storage-firm-calibrant-to-deploy-23mwh-bess-unit-at-new-jersey-data-center/.

Slanger, Dan. 2025. “How Virtual Power Plants Can Help the United States Win the AI Race.” *RMI*, November 6. https://rmi.org/how-virtual-power-plants-can-help-the-united-states-win-the-ai-race/.

Spector, Julian (Canary Media). 2025. "In a First, a Data Center Is Using a Big Battery to Get Online Faster." October 24. https://www.canarymedia.com/articles/batteries/aligned-data-center-get-online-faster.

SPP (Southwest Power Pool). 2025. "High Impact Large Load (HILL) Integration." July. https://spp.org/markets-operations/high-impact-large-load-hill-integration/.

St. John, Jeff (Canary Media). 2025. "Oregon Utility Tries out a Faster, Cheaper Way to Power Data Centers." November 4. https://www.canarymedia.com/articles/data-centers/oregon-utility-tries-out-a-faster-cheaper-way-to-power-data-centers.

Steinberger, Kevin, Tristan Wallace, Ben Joseph, Brendan Mahoney, Melissa Rodas, and Lakshmi Alagappan. 2024. *Utility-Owned Storage in New York State*. Energy and Environmental Economics, Inc. (E3). https://www.ethree.com/wp-content/uploads/2024/10/Utility-Owned-Storage-in-NY.pdf.

Thomas, Michael. 2025. "How to Find Planned Data Centers in the US." *LinkedIn*, October. https://www.linkedin.com/posts/michael-thomas-4b01054a_earlier-this-month-we-launched-our-data-share-7389400339071844353-ZELh/.

Tosado, Gabriella, Ashtin Massie, and Joe Daniel. 2025. "Reality Check: We Have What's Needed to Reliably Power the Data Center Boom, and It's Not Coal Plants." *RMI*, August 12. https://rmi.org/reality-check-we-have-whats-needed-to-reliably-power-the-data-center-boom-and-its-not-coal-plants/.

Turan, Merve, and Wesley Cole. 2024. *Revenue Analysis for Energy Storage Systems in the United States*. NREL/TP--6A40-89906, 2479269, MainId:90685. https://doi.org/10.2172/2479269.

Twitchell, Jeremy B., Devyn W. Powell, Krissy J. Govertsen, and Jess B. Kincaid. 2026. *Energy Storage and the Law of Averages: How Storage Can Make Electricity More Affordable*. Pacific Northwest National Laboratory. https://www.pnnl.gov/publications/energy-storage-and-law-averages-how-storage-can-make-electricity-more-affordable.

U.S. Department of Energy. 2024. *The Future of Resource Adequacy*. U.S. Department of Energy. https://www.energy.gov/sites/default/files/2024-04/2024%20The%20Future%20of%20Resource%20Adequacy%20Report.pdf.

Voltus (Voltus). 2025. "Voltus Launches 'Bring Your Own Capacity' Product for Data Centers." September 30. https://www.voltus.co/press/bring-your-own-capacity-data-centers.

Walker, James (Data Center Knowledge). 2025. "Aligned to Deploy Data Center Battery Storage Project." October 23. https://www.datacenterknowledge.com/energy-power-supply/aligned-to-deploy-first-of-its-kind-data-center-battery-storage-project.

Walton, Robert. 2025. "Base Power, GVEC Partner on 2-MW Texas VPP." *Utility Dive*, July 2. https://www.utilitydive.com/news/base-power-gvec-texas-vpp-virtual-power-plant/752102/.

Walton, Robert. 2026. "Sudden Data Center Load Losses Prompt NERC Alert, Recommendations." *Utility Dive*, April 21. https://www.utilitydive.com/news/data-center-load-disruptions-nerc-alert-recommendations/818036/.

Weaver, Neil (Modo Energy). 2026. "How Does Battery Storage Work in US Electricity Markets?" May 29. https://modoenergy.com/research/en/battery-storage-us-electricity-markets.

Wilson, John D., Sophie Meyer, Zachary Zimmerman, and Rob Gramlich. 2025. *Power Demand Forecasts Revised Up*. Grid Strategies. https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies-National-Load-Growth-Report-2025.pdf.

Wiser, Ryan, Eric O'Shaughnessy, Galen Barbose, Peter Cappers, and Will Gorman. 2025. "Factors Influencing Recent Trends in Retail Electricity Prices in the United States." *The Electricity Journal* 38 (4): 107516. https://doi.org/10.1016/j.tej.2025.107516.

Wozniacka, Gosia. 2026. "PGE Proposes Whopping 29% Rate Hike for Oregon Data Centers; Everyone Else Gets (Slightly) Lower Rates." *The Oregonian*, June 7. https://www.oregonlive.com/environment/2026/06/pge-proposes-whopping-29-rate-hike-for-oregon-data-centers-everyone-else-gets-slightly-lower-rates.html.

Xie, Yiheng, Wenqi Cui, and Adam Wierman. 2025. "Enhancing Data Center Low-Voltage Ride-Through." arXiv:2510.03867. Preprint, arXiv, October 4. https://doi.org/10.48550/arXiv.2510.03867.

Zeng, Angela, and Pat Knight (Synapse Energy). 2025. "Risks of Rapid Data Center Load Growth in Illinois." May 5. https://www.synapse-energy.com/risks-rapid-data-center-load-growth-illinois.

Pacific Northwest National Laboratory

902 Battelle Boulevard
P.O. Box 999
Richland, WA 99354

1-888-375-PNNL (7665)

www.pnnl.gov