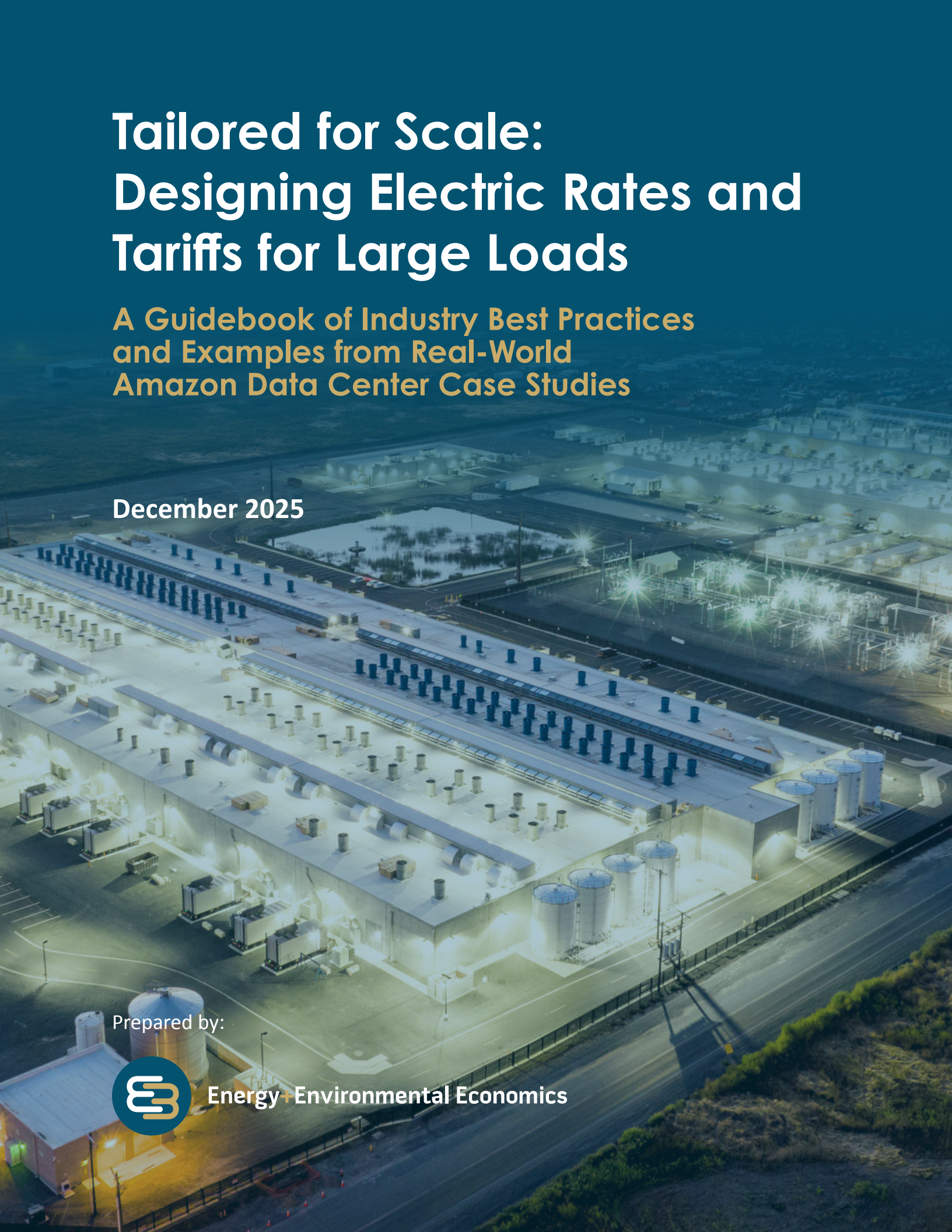
Tailored for Scale: Designing Electric Rates and Tariffs for Large Loads

A Guidebook of Industry Best Practices and Examples from Real-World Amazon Data Center Case Studies

December 2025



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

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Acknowledgments

This report was funded by Amazon, who reviewed the analysis prior to publication. Modeling and analysis for this study was conducted in 2024-2025, based on data provided by Amazon and supplemented with public sources where available. E3 is an independent economic consulting firm, and all report conclusions and analysis are our own.

Recommended Citation

Riu, Isabelle; Patel, Kushal; Mettetal, Liz; Santoni-Colvin, Morgan; et al. *Tailored for Scale: Designing Electric Rates and Tariffs for Large Loads.* Energy and Environmental Economics, Inc. (E3). December 2025. Available at: https://www.ethree.com/ratepayer-study/

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Executive Summary

After decades of flat demand, the United States is seeing new load growth driven by data centers, manufacturing reshoring, and transportation electrification, which is driving major grid investments nationwide and highlighting the need for thoughtful grid planning. New large loads often trigger the need for infrastructure expansion, which can impose costs on the system but also present opportunities to accelerate grid investments, such as in capacity, resilience, and modernization. In addition to driving local investment and job creation to perform these upgrades, newly added capacity can attract further economic development. Given the scale and high utilization of these loads, electricity system costs can be spread over a larger sales volume and generate surplus utility revenue, which can lead to downward rate pressure for other customers. As large loads become more prominent, stakeholders are increasingly questioning whether existing rate designs adequately protect ratepayers from cost increases, or if new structures and frameworks are required.

This white paper begins by outlining the potential benefits, costs, and risks that large loads may present to electric utilities and existing ratepayers. It then examines current rate designs and contract structures used for large loads, highlighting best practices to prevent cost shifting to existing customers. As part of this review, the paper also explores whether current approaches remain effective as large loads grow in scale and complexity. To ground the analysis in real-world outcomes, the paper presents results from evaluating several Amazon data centers, showcasing the impacts data centers are having today and are likely to have in the near future. E3 analyzed data centers across a diverse set of utilities, representing different geographies and market structures, including Pacific Gas & Electric in California, Umatilla Electric Cooperative in Oregon, Dominion Energy in Virginia, and Entergy in Mississippi. Data centers are critical infrastructure that communities and businesses rely on daily, and their importance is growing as cloud computing and AI transform the economy and society. Understanding their impacts on the grid is increasingly important and these quantitative findings contribute a data-driven perspective at the individual data center level.

Key Findings

1 The Amazon data centers evaluated generate revenues that meet or exceed their cost to serve.

*In the case studies, E3 found that Amazon's data centers are projected to generate **$33,500/MW of surplus value** in 2025 that utilities can use for the benefit of their other customers. This means that data centers are not burdening other ratepayers with their costs, rather they could provide a benefit. Assuming a typical data center is 100 MW, this implies **$3.4 million in value per facility** that utilities can use to reduce rates for other ratepayers, but how this potential benefit is realized will differ across jurisdictions. This finding also indicates that the costs to serve these data centers are **not being subsidized by other utility customers** and that existing rate policies are **effectively preventing cost-shifts** on an individual data center basis.*

In the analysis, E3 compared how much the Amazon data centers paid in electric bills (i.e., utility revenue) to the utility's marginal cost to serve the data center. While this "cost to serve" varies widely and is specific to individual utilities, it represents the expenses incurred to provide reliable electricity service to customers, including costs associated with modernizing existing infrastructure, constructing new generation, operations and maintenance, required return on investment, and other items. A utility sets rates to recover these costs plus its regulated rate of return as part of its annual revenue requirement. When comparing the costs and revenues, there are three categories of potential outcomes:

- If the revenues and costs equal each other, there is no impact on ratepayers.
- If costs exceed revenues, the new load may not contribute an equitable amount to system costs which can lead to customer cross subsidization.
- If revenues exceed costs, this surplus net revenue can be used to offset the revenue requirement for other customers, effectively reducing their cost burden and creating downward rate pressure. While the use of this additional margin is at the utility's discretion and subject to regulatory approval, if no action is taken, the additional margin naturally reduces rates as the utility needs to collect less revenue from customers.

E3 examined a diverse subset of Amazon data centers that represent a wide range of sites, regions, and market structures. In all of the case studies, Amazon utility payments generated sufficient or surplus net revenue, providing a neutral or potential positive benefit to other utility customers, such as downward rate pressure, and indicating that these customers are not subsidizing the cost to power the Amazon data centers.

2 This key finding applies to the mid-term as well.

*In 2030, E3 projects that the evaluated data centers could generate potential ratepayer benefits of up to **$6.1 million per 100 MW data center** (based on up to $60,650/MW in surplus utility revenues).*

In these projections, E3 evaluated Amazon data centers in isolation, without modeling underlying system changes to supply and demand, and extended current rate constructs to develop bookend scenarios to illustrate the range of impacts under various resource assumptions. These findings indicate that existing rate policies in many cases have been sufficient in preventing cost shifts, protecting existing customers from excess cost and risk, and even generating potential electric ratepayer benefits.

3 In the long-term, as load growth becomes more dynamic and fast paced, rate design must as well.

Utilities have a menu of tools to mitigate risk and should leverage the best practices outlined in this report to adapt rates as needed to continue to prevent cross-subsidization.

To date, large loads have been served with existing resources or the incremental development of new infrastructure, smoothly integrating into the system over time. But due to the increasing pace and size of this load growth (both on an individual basis and in the aggregate), and system capacity growing increasingly limited in the future, these loads may have a transformational impact on the local interconnecting utility and rate design paradigm. To continue to prevent cross-subsidization, utilities must keep pace and leverage the full range of tools available to them to mitigate these risks (e.g., updated tariff structures and energy supply contracting), based on key factors such as priorities (e.g., relative risk burden on the utility vs. new customer), market structure (e.g., deregulated vs. regulated), and nature of load growth (e.g., incremental vs. new build) in their territory.

4 Large loads can provide meaningful grid, societal, and economic development benefits.

Large loads, especially high load factor customers like data centers, can provide benefits beyond direct benefits to ratepayers.

In addition to potentially generating surplus utility revenue as illustrated in the case studies, large loads drive crucial investments in grid infrastructure beyond their own needs, which can create jobs and attract additional economic development from the expansion and modernization of the grid. Many data centers have also committed to powering their operations with high levels of carbon-free generation, creating strong financial incentives to accelerate the deployment of these resources. In the regions evaluated in the case studies, Amazon is poised to drive nearly 4.2 GW of new solar and wind development, which will produce the energy equivalent to powering over 1 million US homes. Moreover, some of these loads are helping derisk emerging technologies by serving as early adopters. These technologies include small modular nuclear reactors, advanced geothermal and long-duration energy storage, which are expected to be critical to the clean energy transition and could provide a significant societal benefit.

5 New large loads, utilities, and power producers are already innovating.

These include new technologies, regulatory constructs, and contract/financing structures, such as customers self-supplying generation, investing in grid-enhancing technologies (GETs), and signing long-term contracts for emerging clean energy technologies.

These creative solutions help flexibly address current barriers such as capacity constraints and will continue to be important with the new build of thermal resources and additionality of renewable resources. This report outlines the range of options and their trade-offs, which are important for contracting parties and regulatory entities to understand. A few key emerging innovations discussed include:

+ Large loads self-supplying, whether via a power purchase agreement or behind-the-meter contracts, have become increasingly popular, especially with data centers prioritizing faster speed to market.
+ To minimize grid impacts and improve interconnection speeds, an emerging option for data centers is enrolling in non-firm/interruptible utility service and leveraging on-site generation and/or load flexibility as needed.
+ Utilities and large customers are also collaborating on unique and innovative tariff and contract structures, such as supporting carbon-free investments through new financing structures.
+ Hyperscalers and AI-focused data centers are deploying more energy-efficient technologies, such as liquid cooling, leading to significantly lower power usage effectiveness (PUE) and allowing more of the energy used to go towards critical computing tasks.

Motivation and Context

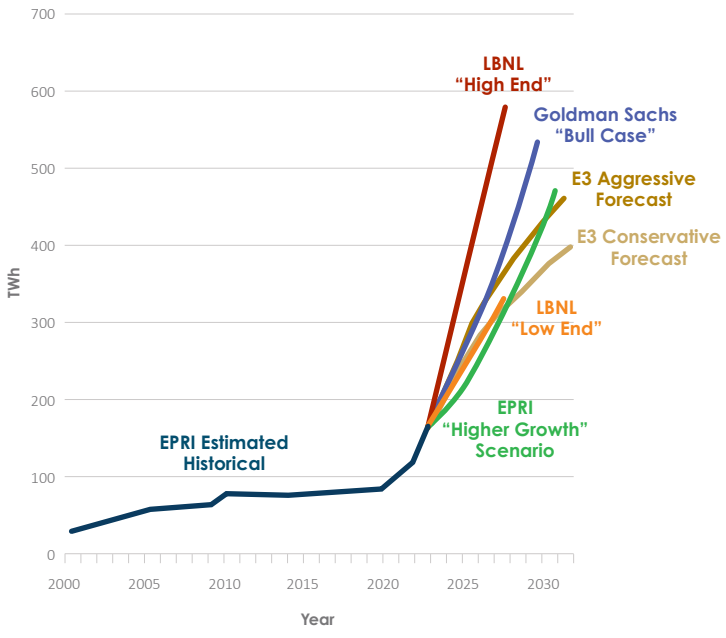
New Large Loads are Transforming Electricity Markets Today

Powering new large loads at the current scale and pace is prompting a transition of today's electricity markets and grid. Traditionally, new sources of electricity demand have been distributed throughout the system and added incrementally, enabling grid planners to adapt gradually through investments in maintenance, distribution upgrades, and periodic capacity upgrades. But the US has seen a sharp uptick in electricity demand, with the rate of growth doubling to 0.9%/year in 2023 from 0.5%/year over the past decade,[1] largely driven by the onshoring of manufacturing, the electrification of transportation, and the expansion of digital infrastructure to support the growth of cloud computing and artificial intelligence (AI). While this growth is occurring nationwide, regions with concentrated data center development are experiencing particularly rapid expansion, requiring new infrastructure such as additional generation sources, and in some cases, new or expanded transmission and local distribution facilities.

These large-scale loads can offer significant economic development benefits, generate large revenues for utilities, and benefit local ratepayers and the grid. They can also have strategic importance, such as the role of data centers in national security and the global race for AI dominance. However, they can pose risks to the electric utility as well. Rate design is an essential mitigation tool to ensure their costs are not shifted onto other ratepayers. As these loads rapidly scale in certain markets, any inadequacies inherent in the current rate design risk becoming magnified. Moreover, these facilities have unique characteristics and are often geographically concentrated, which can create localized stress and add complexity to infrastructure planning. This is a significant challenge for utilities and regulators tasked with serving these new large loads, allocating costs fairly, maintaining grid reliability, and meeting clean energy goals.

The treatment of new large loads under retail ratemaking has always been a challenge, as the framework and pace of retail rate design have been more aligned with smaller, incremental and distributed load growth, but it has recently become a significant concern for utilities, grid operators, regulators, and other ratepayers. For data centers in particular, the initial eras of digitally-driven load growth (from telecom, early cloud computing and mobile internet growth) were offset by consistent efficiency improvements, which helped moderate the energy demand.[2] However, these efficiency gains have not kept pace with increasing demand in recent years, largely driven by AI. Although there is significant uncertainty and potential "hype" around AI and its energy demand, general computing load is still likely to grow due to population growth, demographic shifts, and increasing digitization of the economy. Figure 1 illustrates these various phenomena, with the recent uptick in demand based on Electric Power Institute (EPRI) estimates and various forecasts, including Lawrence Berkeley National Laboratory's (LBNL), indicating that this growth is likely here to stay.[3]

Figure 1: *US Historic and Forecasted Data Center Load Growth*



[1] John D. Wilson and Zach Zimmerman. "The Era of Flat Power Demand is Over." GridStrategies. December 2023. https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf

[2] Daniel Bizo. "Global PUEs – are they going anywhere?". 04 December 2023. https://journal.uptimeinstitute.com/global-pues-are-they-going-anywhere/

[3] Electric Power Research Institute. "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption." 28 May 2024. https://www.epri.com/research/products/3002028905

Shehabi, Arman, et al. "2024 United States Data Center Energy Usage Report." Lawrence Berkeley National Laboratory. December 2024. https://eta-publications.lbl.gov/sites/default/files/2024-12/lbnl-2024-united-states-data-center-energy-usage-report.pdf

"Generational Growth: AI, Data Centers and the Coming US Power Demand Surge." Goldman Sachs. 28 April 2024. https://www.goldmansachs.com/pdfs/insights/pages/generational-growth-ai-data-centers-and-the-coming-us-power-surge/report.pdf

This boom is not without precedent. Rapid infrastructure buildouts have occurred before, such as in the mid-20th century with the creation of the Tennessee Valley Authority and the Bonneville Power Administration. At the time, the regulatory framework was focused on spurring economic development, enabling large industrial customers, such as aluminum smelters, to purchase directly from electricity suppliers to accelerate industrial growth and urbanization. While the U.S. has experienced similar growth periods, today's landscape is vastly different. The sheer volume and speed of load growth, coupled with the higher costs, stricter regulations, and longer timelines, make building large infrastructure far more challenging.

Given this new era of load growth, it is essential to understand the nature of these large loads and how to design appropriate tariffs that reflect their full range of benefits, costs, and risks. This paper proposes a framework for rate design that accounts for the unique characteristics of these loads, including their size, pace of growth, shape and flexibility of demand, and likelihood of materializing in the future. By carefully considering these factors and applying best practices in rate design, utilities and regulators can create a balanced approach that reaps the benefits of large load growth while minimizing potential risks and ratepayer impacts.

Energy Demands of New Large Loads

Data center loads are becoming larger, due to growing demand for cloud computing, AI, and digital services, which have become foundational to daily life. These loads are on a vastly different scale than traditional industrial users; the typical size of a modern data center facility has expanded significantly in recent years, nearly tripling from 30 MW to 90 MW in Dominion Virginia, the world's leading data center market.[4] 'Hyperscalers' have also emerged, a term referring to companies that operate large-scale data centers or campuses, generally at least 100 MW[5] and now reaching the scale of gigawatts.[6] This size shift was fueled in part by the need for specialized processing power for AI workloads, leading to greater power demands; ChatGPT, for example, consumes nearly 10x more electricity than a typical Google search.[7]

In addition to scale, data centers can differ from the typical industrial customer, with their own load growth trends and load characteristics. Although there are different types of data centers, many have large, flat, inflexible loads, as these facilities serve a steady stream of user traffic and can include critical services. These aspects differentiate data centers from other large loads, such as industrial facilities, that may have more a diurnal and/or seasonal pattern of consumption. Ongoing research is examining data center flexibility in light of evolving policies and grid constraints. While this is an important question, this topic is outside the scope of this study.

[4] "Q1 2024 Earnings Call". 02 May 2024. Dominion Energy. https://s2.q4cdn.com/510812146/files/doc_financials/2024/q1/2024-05-02-DE-IR-1Q-2024-earnings-call-slides-vTC.pdf

[5] "What is a hyperscale data center?" 21 March 2024. IBM. https://www.ibm.com/topics/hyperscale-data-center#:~:text=Powell%2C%20Ian%20Smalley-,What%20is%20a%20hyperscale%20data%20center?,offer%20hyperscale%20data%20center%20services

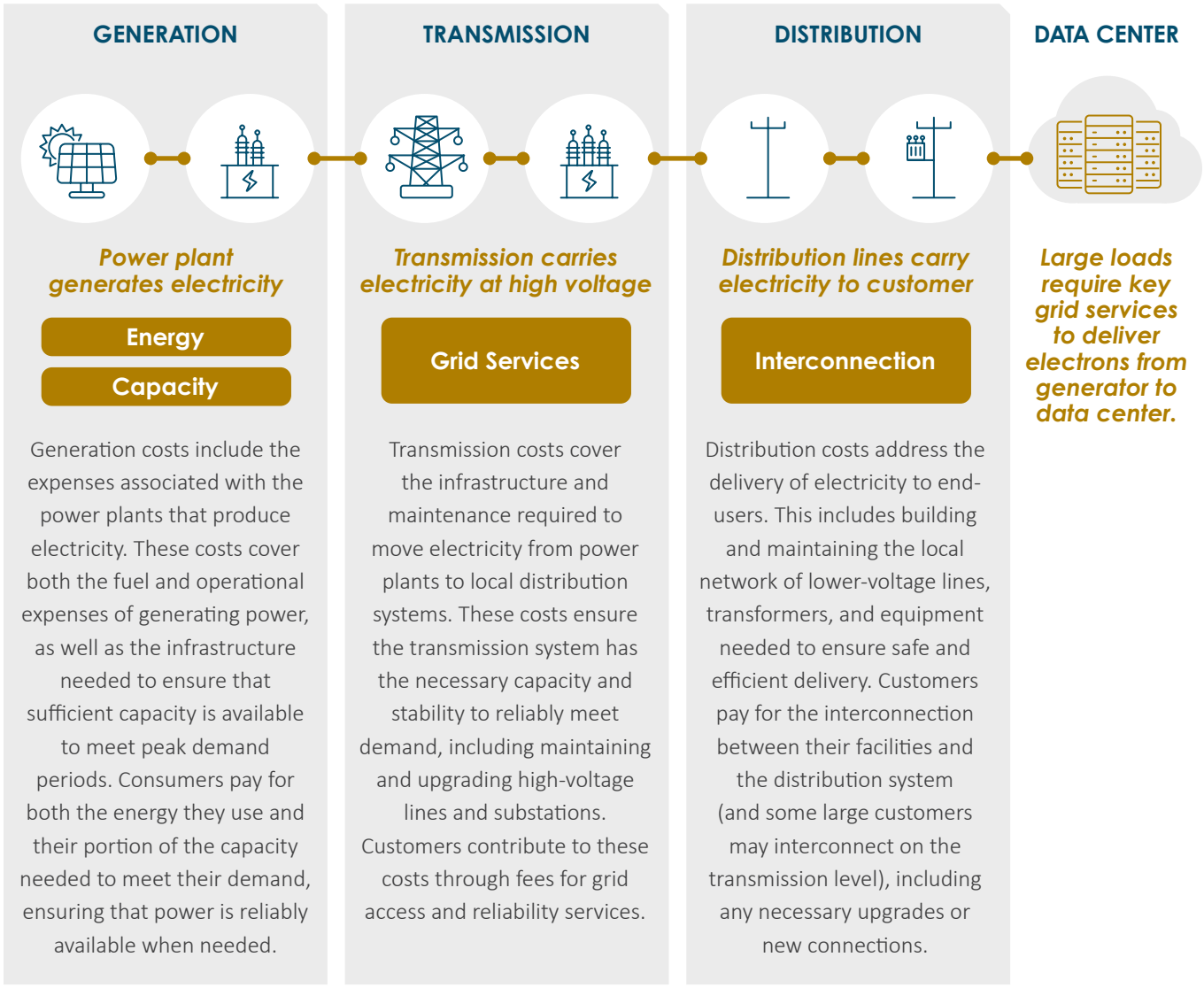
[6] "The Gigawatt Data Center Campus is Coming." 29 April 2024. Data Center Frontier. https://www.datacenterfrontier.com/hyperscale/article/55021675/the-gigawatt-data-center-campus-is-coming

[7] "Electricity 2024: Analysis and Forecast to 2026." International Energy Agency. https://iea.blob.core.windows.net/assets/6b2fd954-2017-408e-bf08-952fdd62118a/Electricity2024-Analysisandforecastto2026.pdf

Electricity Services Required to Serve Large Loads

Designing electric rates for large loads, particularly data center loads is challenging due to the magnitude of growth in the industry and the associated risks, which are at odds with the traditional ratemaking process. Before delving into this challenge and the best practices more deeply, it is important to understand the major electric services provided to large loads, which can be categorized into three key areas: generation, transmission, and distribution.

Figure 2: *Overview of Major Electric Services*



Traditionally the utility acts as an intermediary between the customer and the power market, using a bundled service rate designed to reflect the average cost of providing electricity across generation, distribution and transmission. In markets with retail choice (i.e. the ability to choose generation supply from a non-incumbent utility provider), large loads can have direct access to retail electricity supplies and choose a supplier from a range of competitive providers, typically based on price and renewable options. The utility still plays a key role and remains obligated to provide generation service if the customer chooses to come back to full service, but is limited to the transmission and distribution of the electricity in addition to providing billing services and maintaining grid reliability.

Impacts of New Large Loads

Potential Benefits of New Large Loads

Large loads, especially those with high load factors such as data centers, can create a range of meaningful benefits to the local grid and ratepayers, such as creating surplus utility revenue, investing in grid infrastructure beyond their own needs, and prompting new deployments of renewables and de-risking emerging clean technologies.

Surplus Utility Revenues and the Potential for Downward Rate Pressure

New large loads add both revenues and costs to the system. Utilities earn revenue through the rates they charge customers for providing electricity service. Rates are structured to cover the utility's costs of operation, including infrastructure investment, operating expenses, and maintenance, while also allowing the utility to earn a reasonable rate of return on its capital investment. Rate design comes in many variations, as discussed in the next section, but generally considers both marginal and embedded costs.

- Embedded costs reflect existing grid costs. They are the historical or average costs incurred by the utility to provide service, including the costs of building and maintaining the grid, power plants, and other infrastructure. These average costs are used to set base rates for different customer classes, ensuring that the utility collects enough revenue to meet its obligations.
- Marginal costs reflect the cost to the utility to serve an additional unit of electricity demand at a given time. They are the prevailing costs in power markets and/or the costs of new infrastructure build.

Ensuring the revenue from the new large load meets or exceeds the marginal cost of service will help prevent existing customers from subsidizing the new large loads. In other words, if revenue generated from a new customer equals the marginal cost incurred by that customer, there will be a neutral impact to other ratepayers. If the new customer also contributes to existing embedded costs, downward rate pressure could occur, as the existing system costs are spread over a larger denominator of sales, effectively reducing the cost burden on all ratepayers. This could occur both in the scenario when the large new load is served by new build infrastructure and when it's served by existing headroom, as long as the load is contributing to existing embedded costs (e.g., existing infrastructure and/or public purpose programs). The revenues collected from customers via rates are used to cover the utility's operational and capital expenses, pay debts, invest in infrastructure, and provide a return to shareholders or reinvest into the utility's business, depending on its business model. Any net revenue in excess of the regulated rate of return can be used to inform updates to cost allocation factors, which reflect the contributions of each customer rate class toward total system demand and consumption. This update can decrease other class allocations, effectively reducing their cost burden and providing a benefit to those classes of customers. The utility ratemaking and cost allocation process is covered in more detail in the Rate Design Toolkit for Large Loads Today section.

Investments in Grid Infrastructure Beyond their own Needs

The integration of new large loads has the potential to drive significant investments in grid infrastructure that extends beyond the customers' own needs. As data centers require substantial and continuous power, they often trigger and provide cost recovery for the development of new infrastructure, which not only serves them but also contributes to modernizing and hardening the broader electricity grid. These upgrades may include the construction of new substations or reliability enhancements which benefit not only the large customers but also the surrounding communities and businesses.

Large loads also contribute to existing shared infrastructure costs, helping to offset the cost burden of critical grid upgrades on other ratepayers, leading to a more equitable distribution of costs. This is a significant benefit, as the current grid is generally in need of modernization and ill-equipped to manage the demands of the future such as the clean energy transition. For example, new high-capacity transmission lines built to service data centers could also support local residential and commercial load growth, effectively expanding grid capacity for everyone, reducing operations and maintenance costs, stimulating local economic development, and enabling distributed energy resources. Additionally, utilities may use revenue generated from large consumers to fund future grid projects that benefit all users, such as reliability enhancements or clean energy investments. For example, the PJM Board approved new transmission projects to support grid reliability as the region experiences load growth from data centers as well as transportation and

building electrification, and transitions to a cleaner generation mix.[8] Amazon has helped contribute to these infrastructure upgrades as a retail customer.

In response to large loads, utilities may implement grid enhancing technologies (GETs) and advanced conductors to help transmission lines carry more power. Amazon has helped evaluate the value of GETs to support their deployment, such as its recent study in collaboration with RMI which found that GETs could help interconnect 6.6 GW of carbon-free energy in Illinois, Indiana, Ohio, Pennsylvania and Virginia by 2027.[9] Utilities may also deploy more sophisticated monitoring and control systems to better manage peak demand and support the integration of distributed energy resources like solar or wind power, which are often variable and geographically dispersed. Amazon has invested in these grid modernization technologies, such as at the Baldy Mesa solar and battery storage site where machine learning models powered by Amazon are used to predict optimal times for the battery to charge and discharge energy back to the grid.[10] Pairing solar and battery projects with AI technologies ensures a steadier supply of carbon-free energy for more hours each day, while also helping to reduce grid congestion during peak periods. These types of infrastructure and technical upgrades could also improve grid reliability for all users by reducing bottlenecks, enhancing load balancing, and enabling quicker responses to disruptions or outages.

Although new investments to support large loads can offer benefits beyond their initial needs, these benefits may not be immediately apparent or fully quantifiable at the outset. For example, a large load customer may be first to expand in an area and trigger grid upgrades it pays for, but if subsequent customers build in that same area and benefit from the initial investment, the initial customer should see a commensurate benefit flow back in accordance with how the infrastructure was funded. A process should be developed to regularly identify these benefits over time, ensure they are accurately tabulated, and enable refunds or credits issued back to the customers as needed. This process has already been standard practice for large loads in several jurisdictions, such as in open access transmission tariffs (e.g., in Bonneville Power Administration) and in PG&E's proposed Electric Rule 30.[11] More broadly, given the inherent uncertainty of large load growth, innovative regulatory structures and flexible approaches will be essential to understand benefits and actively manage risks.

Deploying Carbon-Free Energy

Many data center operators have committed to powering their operations with 100% carbon-free energy, creating strong financial incentives to increase the deployment of these resources. This commitment drives demand for large-scale renewable energy and storage systems, making clean energy investments more financially viable by fostering economies of scale. For example, Amazon has committed to matching all of the electricity consumed by its operations with 100% renewable energy- a goal it achieved 7 years early in 2023. Reaching this goal has included:

- Investing billions of dollars in over 600 solar and wind projects globally – enough to power the equivalent of more than 8.3 million US homes.
- Enabling over 300 utility-scale projects with its critical investments, providing new sources of energy to the grid.
- Building over 300 on-site solar projects, generating renewable energy directly for Amazon buildings.

Moreover, across the regions analyzed in the case study, the company is poised to enable nearly 4.2 GW of new solar and wind.

Beyond voluntary commitments, large loads and utilities have been collaborating on unique and innovative rate designs and contract structures to power operations with carbon-free energy. For example, Duke Energy recently announced an agreement with Amazon and other large customers to enable them to directly support carbon-free investments through innovative financing structures under its Accelerating Clean Energy tariffs.[12] NV Energy's Clean Transition Tariff allows large customers to purchase new renewables and emerging technologies, such as geothermal, with the goal of accelerating the adoption of dispatchable clean energy. On a bilateral contract basis, Amazon recently announced a first-of-its-kind agreement with Entergy to enable 650 MW of new renewable energy projects in Mississippi over the next three years.[13] Additional information on these mechanisms and tariffs is included in the Appendix.

[8] PJM Inside Lines. 26 February 2025. "PJM Board Approves New Transmission Projects to Support Grid Reliability." https://insidelines.pjm.com/pjm-board-approves-new-transmission-projects-to-support-grid-reliability/

[9] "Addressing Grid Capacity Constraints with Grid-Enhancing Technologies (GETs)." Amazon for Industries Blog, Amazon Web Services, 8 Feb. 2024, https://aws.amazon.com/blogs/industries/addressing-grid-capacity-constraints-with-gets/.

[10] "How Amazon is Harnessing Solar Energy, Batteries, and AI to Help Decarbonize the Grid." About Amazon, 21 May 2024, https://www.aboutamazon.com/news/sustainability/carbon-free-energy-projects-ai-tech.

[11] "Application for Approval of Electric Rule No. 30 For Transmission-Level Retail Electric Service." 21 November 2024. Pacific Gas and Electric Company. https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2411007/7851/547330908.pdf

[12] "Responding to Growing Demand, Duke Energy, Amazon, Google, Microsoft and Nucor Execute Agreements to Accelerate Clean Energy Options." PR Newswire, 29 May 2024, https://www.prnewswire.com/news-releases/responding-to-growing-demand-duke-energy-amazon-google-microsoft-and-nucor-execute-agreements-to-accelerate-clean-energy-options-302158155.html.

[13] "Amazon Announces New Training Programs and Renewable Energy Projects in Mississippi." About Amazon, 20 May 2024, https://www.aboutamazon.com/news/aws/aws-training-programs-sustainability-projects-mississippi.

In addition to potential ratepayer benefits, large loads can generate potential societal benefits as well, such as by helping derisk emerging technologies expected to be critical to the clean energy transition, such as small modular nuclear reactors (SMRs), nuclear fusion, advanced geothermal, or long duration energy storage. These large customers can offer stable revenue streams to enable the development of these technologies, which face significant cost and regulatory uncertainties. By providing commitments, such as via long-term power purchase agreements (PPAs), these large customers help reduce exposure by taking on the first-of-a-kind project risk and providing financial stability with a reliable offtake for the energy generated, helping attract further investment and putting downward pressure on the future costs of these technologies. For example, Amazon recently signed agreements to support the development of SMRs in Washington and Pennsylvania.[14]

In short, data centers can act as a catalyst for modernizing the grid, improving reliability, and increasing clean energy deployment. By aligning the needs and features of large consumers with broader grid objectives, utilities and regulators can create win-win scenarios, where the requisite infrastructure investments not only meet the customer's needs but also provide lasting benefits to the entire system.

Potential Challenges and Risks of New Large Loads

Large load customers and utilities often have divergent concerns and priorities for interconnection and electric rates, posing challenges and risks. For example, data centers and other large loads often want certainty that they can interconnect and energize as quickly as possible, flexibility to exercise choice in relatively low-cost and reliable energy generation sources, and assurance that they will pay a fair share of costs. Utilities are concerned about building the requested infrastructure, the forecasted load growth not materializing or under-consuming, and then having to manage stranded asset costs and upward rate pressure. It is critical to understand these factors and balance the concerns when designing tariffs.

Scale of New Large Loads Generally Require New Investment

The size of the new load, especially in relation to the utility territory and local grid, have required a rethinking of how tariffs are designed for these customers. Fundamentally, many new large loads require major near-term investments instead of smaller, long-term investments. To date, most data center load additions have been incremental and rolled into utility rates. But there is an increasing frequency of load additions rivaling or even exceeding the size of system load in many utility territories. This phenomenon will only continue given the large growth forecasts as illustrated in Figure 1, underscoring concerns about utility risk and ratepayer impacts.

As demand increases at this scale, marginal supply costs can increase and raise costs for customers until more supply is added and the system regains equilibrium. This can occur despite data centers paying their "fair share" of costs and is not an explicit source of inequity. However, this dynamic only occurs at a system-wide level beyond any individual data center, which is out of scope of this analysis. For a deeper exploration of this issue, see E3's study for the Virginia Joint Legislative Audit and Review Commission (JLARC) which focused on the impact of data centers in the aggregate.[15]

Rapid Pace of Large Load Growth Challenges Cost Allocation Practices

The rapid pace of this load growth is misaligned with the slow and infrequent cadence of electric utility rate design and cost-of-service studies. These studies assess the costs of serving customer classes based on historical usage patterns and infrastructure investment but were not designed for the current level and pace of load growth. As a result, the estimated cost to serve new customers can quickly become outdated and inaccurate, and utilities may struggle with recovering costs in a timely or equitable manner, potentially leading to cost shift. Although truly accurate cost allocation is unrealistic, as it requires perfect foresight and continuous real-time realignment, it may be imperative for utilities facing significant load growth to more frequently update their studies to mitigate this risk. E3's study for the Virginia JLARC also explores this topic in more depth.[16]

[14] "Amazon Enlists Nuclear Small Modular Reactors in Push for Net Carbon-Zero." About Amazon, 16 Oct. 2024, https://www.aboutamazon.com/news/sustainability/amazon-nuclear-small-modular-reactor-net-carbon-zero.

[15] Energy and Environmental Economics. "Virginia Data Center Study: Electric Infrastructure and Customer Rate Impacts." https://jlarc.virginia.gov/pdfs/presentations/JLARC%20Virginia%20Data%20Center%20Study_FINAL_12-09-2024.pdf

[16] Energy and Environmental Economics. "Virginia Data Center Study: Electric Infrastructure and Customer Rate Impacts." https://jlarc.virginia.gov/pdfs/presentations/JLARC%20Virginia%20Data%20Center%20Study_FINAL_12-09-2024.pdf

Uncertainty in Loads Materializing and the Overall Long-Term Load Outlook

Large loads can carry uncertainty due to individual characteristics and/or broader market trends, which can influence how utilities plan, invest, and manage risk over the lifecycle of the loads. For example, large loads vary widely (such as by segment, size, type), each carrying a unique risk profile. Generally, all loads that enter the interconnection queue are evaluated sequentially and equally, which can pose a challenge to utilities. Effectively serving these loads requires ongoing investment across their lifecycles, so aligning infrastructure development with actual demand is critical to managing risk and avoiding overbuilt capacity and stranded assets.

More broadly, these loads can be subject to more macro uncertainties as well, such as:

- Uncertainty around AI's future, namely how and to what degree AI will be used as well as the impact of potential efficiency improvements (such as processor improvements or liquid cooling), which all have significant ramifications on data center energy usage.[17]
- Uncertainty around the degree of speculation in interconnection requests which likely make up a non-negligible portion of queues. These speculative interconnection requests can come from both within the same company as developers hedge their bets on site selection within a single utility territory as well as requests from less serious actors that are unlikely to materialize.

These concerns are legitimate and should be managed but should also be put in perspective, especially as uncertainty in forecasting is nothing new. Data centers, like the industrial loads that once helped expand the early electric grid, are acting as strong offtakers for new generation and driving critical infrastructure investments. However, unlike this previous era, today's regulatory and planning frameworks are not designed to efficiently integrate rapid and concentrated load growth, especially given the past few decades of flat load growth. This shift is compelling new risk mitigation strategies, revised planning approaches, and accelerated grid modernization. These changes have the potential to benefit a broad set of stakeholders, including other ratepayers and other new large loads such as electric vehicles. Moreover, data centers are often located in large population centers, increasing the likelihood that the grid investments they spur will be broadly used in the long run. In short, effectively navigating these challenges will require a balanced approach—one that addresses risks while ensuring the opportunities driven by data centers are equitably managed across all stakeholders.

[17] Illustrative explorations of the impact of these factors on data center energy usage through 2045 are covered in: I. Riu, D. Smiley, S. Bessasparis, K. Patel, "Load Growth Is Here to Stay, but Are Data Centers?: Strategically Managing the Challenges and Opportunities of Load Growth," Energy and Environmental Economics, Inc., July 2024. https://www.ethree.com/wp-content/uploads/2024/07/E3-White-Paper-2024-Load-Growth-Is-Here-to-Stay-but-Are-Data-Centers-2.pdf

Rate Design Toolkit for Large Loads Today

Current Approaches to Charging Electric Loads for Electric Grid Needs

Utility Rate Design Process

In translating these cost categories into rate design, utilities have generally adhered to James Bonbright's "Principles of Public Utility Rates" which has served as the industry standard for decades, with principles that include the following:

- **Adequacy:** Rates should be designed to enable the utility to recover its costs adequately and feasibly.
- **Equity:** Rates should be designed to ensure costs are fairly allocated between rate classes and avoid undue discrimination.
- **Efficiency:** Rates should encourage efficient use of resources, minimizing wasteful usage and promoting conservation.
- **Acceptability:** Rates should be transparent, understandable, stable, predictable, and simple.

Although all these objectives are important elements of rate design, they sometimes compete and are often debated in rate design proceedings. For example, designing efficient rates that reflect utility costs can increase rate complexity. Additionally, rates may result in inequities when they are not aligned with utility costs or when they are simplified to enhance acceptability. In practice, rate design balances the rate design principles, often resulting in compromise and tradeoffs.

Large loads challenge the traditional rate design frameworks given their size, scale and pace of buildout, which far exceeds historical rates

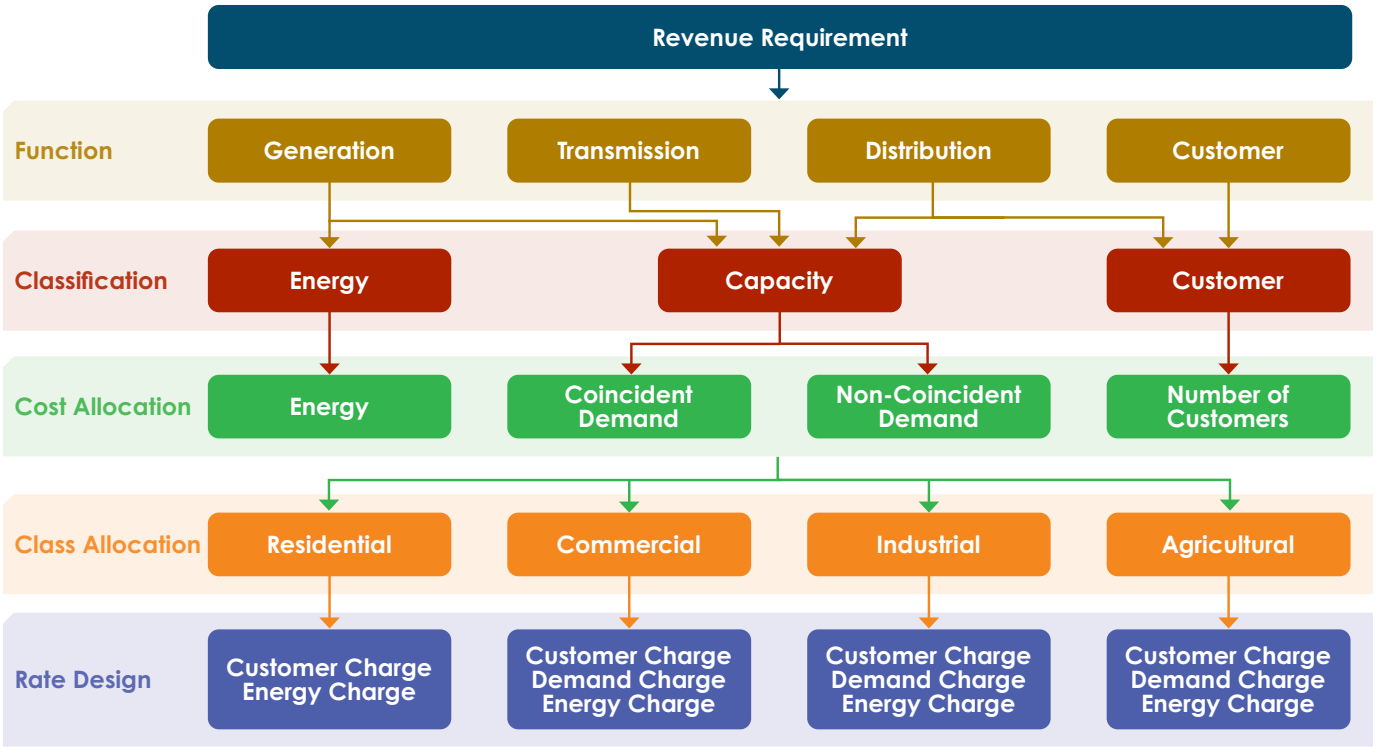
Sometimes, an outcome of balancing the rate design principles includes cross subsidization, which occurs when higher rates for one customer class subsidize lower rates for another customer class. Another outcome is some customers end up paying more or less than the average amount for a customer in their class. These outcomes are not always undesirable. For example, rural customers generally cost more to serve than urban customers due to distribution infrastructure requirements, but these rural customers are typically charged the same rate as urban customers to promote equity and acceptability. Additionally, some level of cross subsidization is often acceptable to support low-income programs or other "public purpose" programs.

Figure 3 below illustrates the process of rate design. Utilities design electric rates or charges to establish the utility revenue requirement, or cost of service, which is the total revenue the utility can collect through its rates and the total cost incurred by the utility to provide electric service to customers which for investor-owned utilities also includes a return on capital investments. Utility cost of service studies then allocate the costs among the customer classes including residential, commercial, industrial, and agricultural customers. Utility costs are first categorized by function such as generation, transmission, distribution, customer, and overhead costs, and then classified as energy-, demand-, or customer-related.

Energy-related costs vary with the amount of energy a customer consumes and include costs such as fuel costs. Demand-related costs vary with the customer's maximum demand. These costs are generally fixed costs associated with the generation, transmission, and distribution system. Customer-related costs are fixed costs such as billing and metering that do not vary with either energy or demand but with the number of customers or other factors. Finally, the costs are allocated among the customer classes. If certain costs can be wholly attributed to one customer class, the costs are directly assigned to that customer class. If not, the costs are assigned to each customer class using allocation factors.[18]

[18] The allocation factors are developed based on "cost causation," which reflects the contribution of each customer class to the costs using metrics such as energy delivered, demand both coincident and non-coincident with the utility system peak, number of customers, and customer voltage level.

Figure 3: Utility Rate Design Process



Rate Design Elements

The utility designs rates to collect the accepted revenues and recover costs while also considering the other principles of rate design such as equity, efficiency, and acceptability. Electric rates typically include two or three charges, depending on the customer class. Residential and small commercial customers often have energy and customer charges whereas large commercial and industrial customers have three-part rates with energy, demand, and customer charges. The energy charge is based on electricity consumption and can be a flat $/kWh rate, vary according to total consumption, or vary with time of day and/or season. The demand charge is based on the customer's maximum consumption coincident or non-coincident with the utility system peak. The customer charge is typically a fixed charge used to recover utility costs associated with items such as metering and billing.

Large customers generally have more complex rate structures, which allows for more efficient functionalization and classification of costs. For example, time-of-use rates, which charge different prices based on demand throughout the day, can apportion system costs more fairly. Another example of rate variability is firm or non-firm service, where customers can pay lower rates for power supply that the utility can curtail during system constrained hours.

Potential Cost Allocation and Recovery Issues

When rate structures are misaligned with utility costs, there can be an under- or over-collection of revenues from a given customer class. For example, a portion of a utility's fixed costs are often recovered through volumetric energy charges even though those costs are not variable with energy consumption. Over time, fluctuations in customer usage may cause changes in utility revenue that differ from the changes in utility costs. Thus, for a utility to help ensure it meets its revenue requirement, it must periodically adjust its rates, such as by updating cost allocation factors.

This issue is further compounded by regulatory lag, which is the delay between when a utility incurs costs and when those costs are reflected in customer rates. This delay is largely due to the slow and methodical nature of the ratemaking process, but some jurisdictions, particularly smaller utilities or territories with little to no growth, rarely or never update their cost allocations. As a result, rate structures become outdated, failing to accurately reflect changes in the utility's cost dynamics. As previously discussed, the current pace of updating cost allocation factors may be insufficient to match anticipated load growth, thus utilities must reconsider the frequency of updates to better align with the scale and speed of large load increases to avoid ratepayer impacts.

Existing Tariffs and Contracts for Large Loads in the Market Today

Given data centers' unique attributes, utilities have developed a wide variety of rate designs for large loads in an effort to balance competing priorities including minimizing risk and ratepayer impact, generating economic development, and furthering clean energy goals. Table 1 provides several examples of existing and proposed rates for large loads, from the major data center markets including the largest in Northern Virginia. These examples illustrate the use of specific eligibility terms (such as minimum size, minimum load factor, data centers only) and tools to derisk (such as minimum bills/demand charges, minimum contract lengths and exit fees, minimum credit ratings, refundable deposits, ramp schedules, and creating a separate rate class). Additional discussion of derisking tools is included in the Risk Mitigation Toolkit section and additional tables illustrating existing tariff structures from the major US data center markets are included in the Appendix to demonstrate the wide range of tools used in more detail.

Table 1: *Examples of Utility Rate Designs for Large Loads*

Utility Tariff	Status	Eligibility	Distinct Elements	Interconnection Fees	Contract Length	Clean Share of Gen.
APS *Extra High Load Factor (XHLF)*	Existing	≥ 15 MW, ≥ 92% load factor	Minimum bill specified in contract	Refundable; tied to revenue	Customer agreement required	≥ 50%
Georgia Power *High Load Factor (PLH-13)*	Existing	≥ 10 MW, ≥ 75% load factor	Minimum demand charge of at least 60%	Deposit may be required, 5y refund	5 years	N/A
Dominion *(GS-4)*	Existing	≥ 500 kW	Time-of-use pricing	Minimum bill required	N/A	Per separate voluntary tariff
Dominion *(Market Based Rate)*	Existing (Pilot)	≥ 5,000 kW	Market-based pricing	Minimum bill required	3 years	Per separate voluntary tariff
Indiana Michigan Power *Industrial Power Tariff*	Existing	≥ 70 MW or ≥ 150 MW across a company; collateral requirement	Min. demand charge (80%); capacity reduction option (20%)	N/A	Ramp (5y); Term (12y); "Exit fee" option	Working on separate clean transition tariff
AEP Ohio *Data Center Power Tariff*	Existing	Data centers; ≥ 25 MW; min. credit rating	85% minimum demand charge	100% of buildout costs if customer cancels	Ramp (4y); Term (+8y); "Exit fee" option	N/A

These rates showcase the beginning of an evolution in utility rate design, illustrating the varied approaches to managing the costs, benefits, and risks of this large load growth. For example, the Indiana Michigan Power tariff, approved in February 2025, requires long-term financial commitments proportional to the load's size to mitigate utility and ratepayer risk. This approach ensures "costs to serve these large load customers are reasonably recovered and not passed on to existing customers" in addition to providing grid modernization reliability benefits to all customers.[19] It's also important to note that data centers are working outside of the utility procurement paradigm as well for faster speed to market, such as by procuring their own resources via co-location or power purchase agreements in the short and long term, which is examined in more depth in the next section.

[19] American Electric Power. 19 February 2025. "Indiana Michigan Power Receives Order in Large Load Settlement." https://www.aep.com/news/stories/view/10037/

Best Practices and Rate Design Options

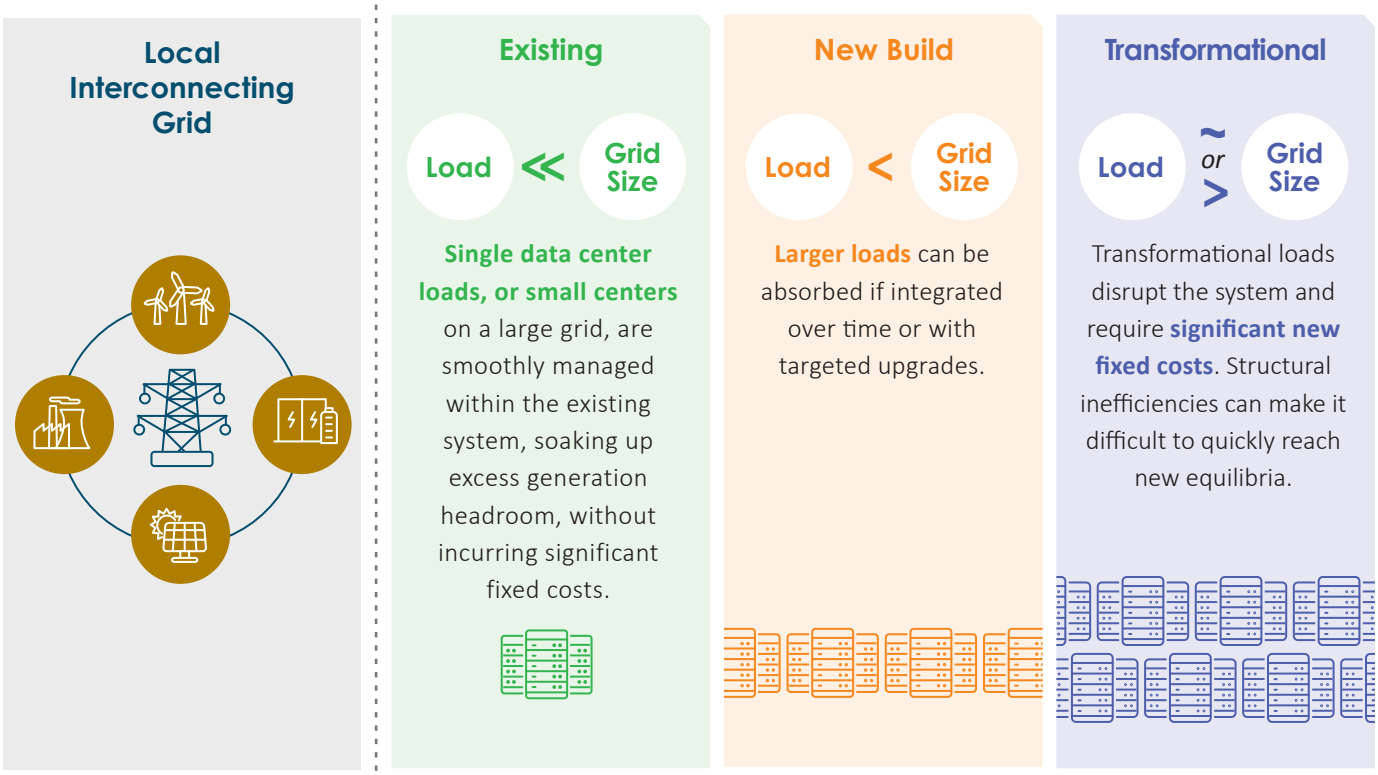
Rate Design Options

Grid Integration Categories

To evaluate appropriate rate designs for this load growth, we categorize the large loads into three overarching categories. These categories reflect how the new load is served, based on the relative size of the load to the local connecting grid to capture the scale of potential impact. For example, the system impacts and preferred rate designs differ for a smaller new load in a large utility territory (which is unlikely to make a significant impact) versus the first large load integrating into a small utility territory, which may be more disruptive and magnify any inefficiencies in the current rate design.

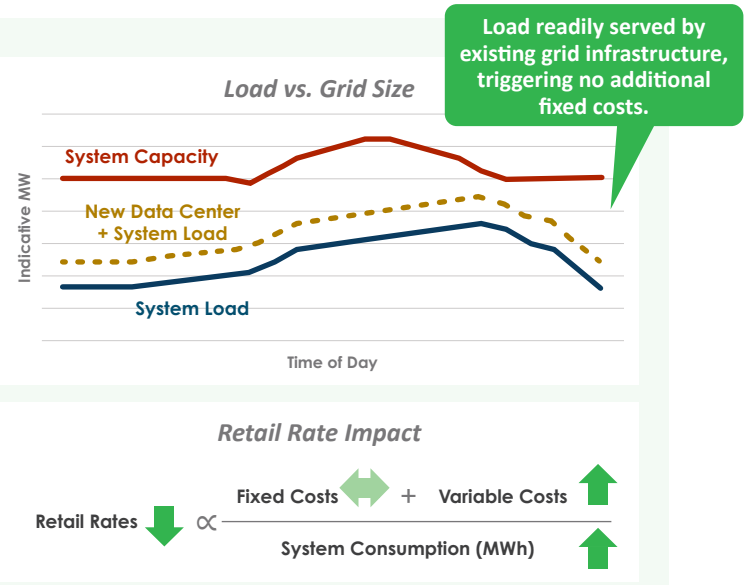
To date, there have largely been two categories: data centers served with **Incremental** usage of existing resources or triggering **New Build**. The third category, which will become increasingly relevant in the long term, is for extremely large loads that have a **Transformational** impact on the system and cost allocation. Figure 4 illustrates these relationships at a high level, followed by a detailed summary of each category, illustrating the impact on potential costs, risks and benefits.

Figure 4: *New Data Center Investments Categorized by Potential Impact to the Grid*



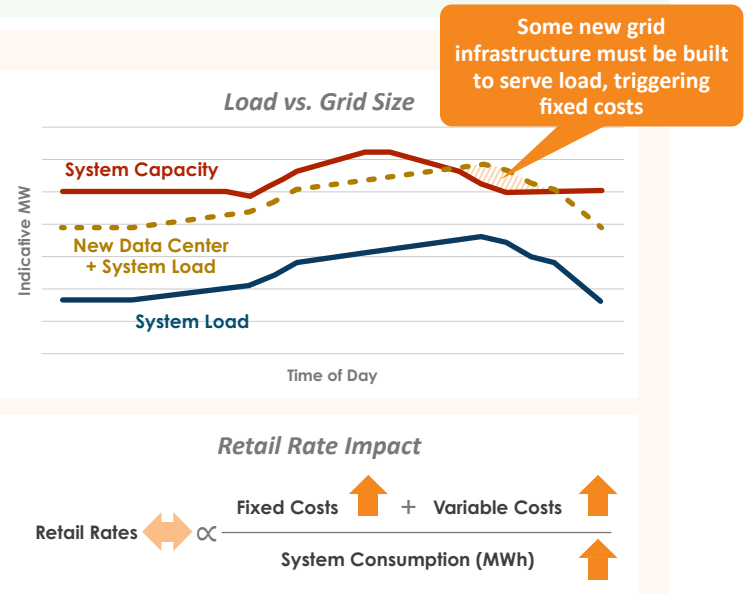
"Incremental" Loads: Data Center Served by Incremental Usage of Existing Resources

On one end of the spectrum is the "Incremental" scenario which includes smaller loads in larger utilities and/or utilities with sufficient existing headroom. In this hypothetical scenario, the load is served by existing grid infrastructure, with no new infrastructure built and thus no additional fixed costs triggered. The customer largely pays for the incremental variable cost to serve its load along with local upgrades to the distribution system needed to meet the new load requirements, such as requiring a high level of reliability (i.e. interconnection redundancy) as is common for data centers. If the customer also contributes to existing fixed costs, there can be downward pressure on retail rates, as the costs are spread over a larger denominator of sales.



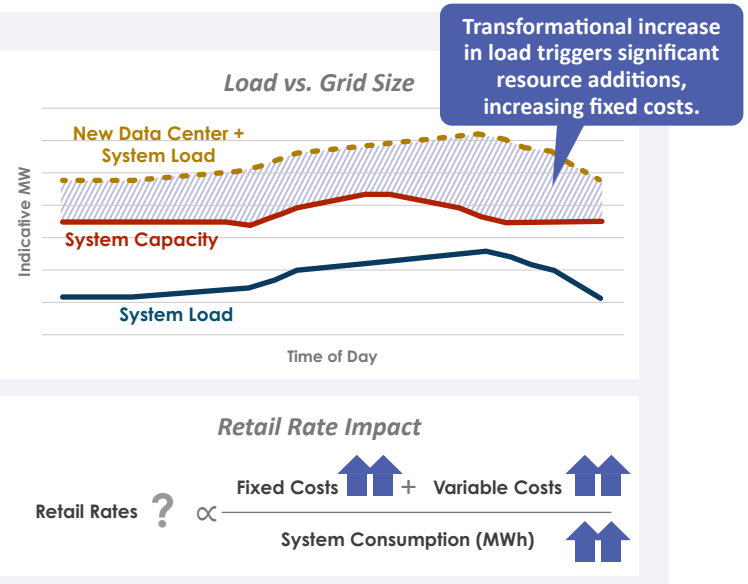
"New Build" Loads: Data Center Served by New Resource Builds

Once available headroom is exhausted, new resources will have to be built to serve the new load, triggering fixed costs in addition to the variable costs. As displayed in the case studies, this category is generally a higher cost scenario, given the required new build. If the new customer pays for the new build, the retail rate impact could be neutral (as illustrated below); if the new customer also contributes to existing fixed costs, there can be downward rate pressure (as illustrated above). There can also be cost-effective alternatives to the utility building new infrastructure, especially if the new system load exceeds system capacity for only a few hours a year, including customer load flexibility or using on-site generation.



"Transformational" Loads: Data Center Served by Significant New Resources, Transforming the Local Grid

Extremely large loads, especially those dwarfing smaller utility territories, and in the aggregate, can have a transformational impact, breaking down the typical rate dynamics. Transformational load requires the utility to build significant new resources (such as generation and transmission), which can complicate cost allocation given the shared nature of the resources and cost-of-service studies becoming irrelevant given the scale and pace of the load. Moreover, given the incongruity between the size of the load and the utility, the scale of the stranded asset and cross-subsidization risks increase, such as if the load fails to materialize or exits early. The utility should pay particular attention to using the risk mitigation toolkit to ensure tariffs are structured to pay their fair share (e.g., sufficiently collect embedded costs) and protect its existing ratepayers. And although the focus of this paper is not on data centers in the aggregate, it is important to recognize that transformational load growth may become more prevalent in the future as large loads grow in terms of individual size and the impacts of data centers as a whole.



Archetypes

Delving a level deeper below these three overarching categories, there are a number of parameters utilities and regulators should consider to determine their relevant rate design options classified here as "archetypes". Figure 5 outlines the key elements to help determine a utility's relevant archetype, including the nature of the load growth, the condition of the local grid, and the utility's priorities.

Applying these Grid Integration Categories and the Archetype Conceptual Decision Tree to the utility cost functions produces a menu of options on how to serve the load. Figure 6 illustrates this as an inverse pyramid, demonstrating how there can be increasing complexity and options the further you get from the data center point of interconnection. Distribution is fairly straightforward, given the shorter distance to the grid and discrete link from the new customer to the system, and largely depends on existing headroom. In contrast, the transmission level is more complex, with more configurations that depend on the market structure, and even more options at the generation level, depending on the size of load and utility and customer priorities. Data centers take service on distribution or transmission levels, depending on facility size, location, and other factors.

Figure 5. *Archetype Conceptual Decision Tree*

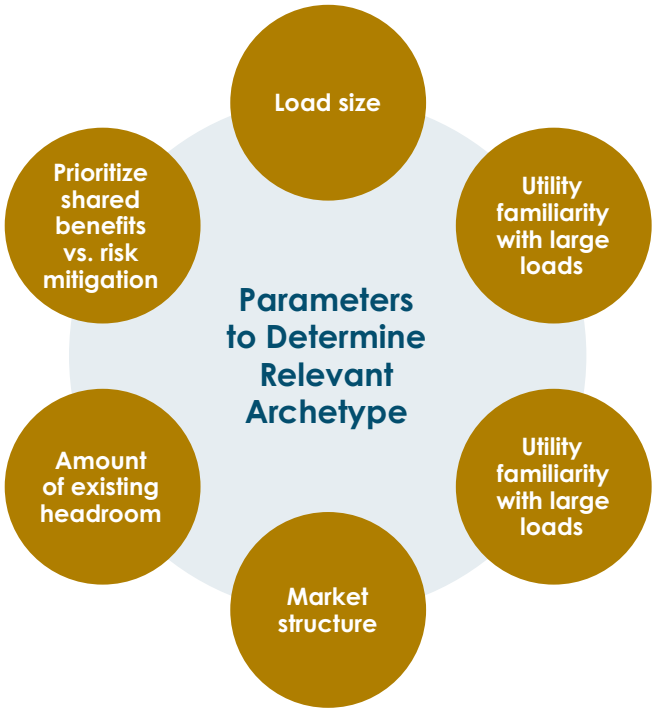


Figure 6. *Configurations/Options for Generation, Transmission and Distribution*

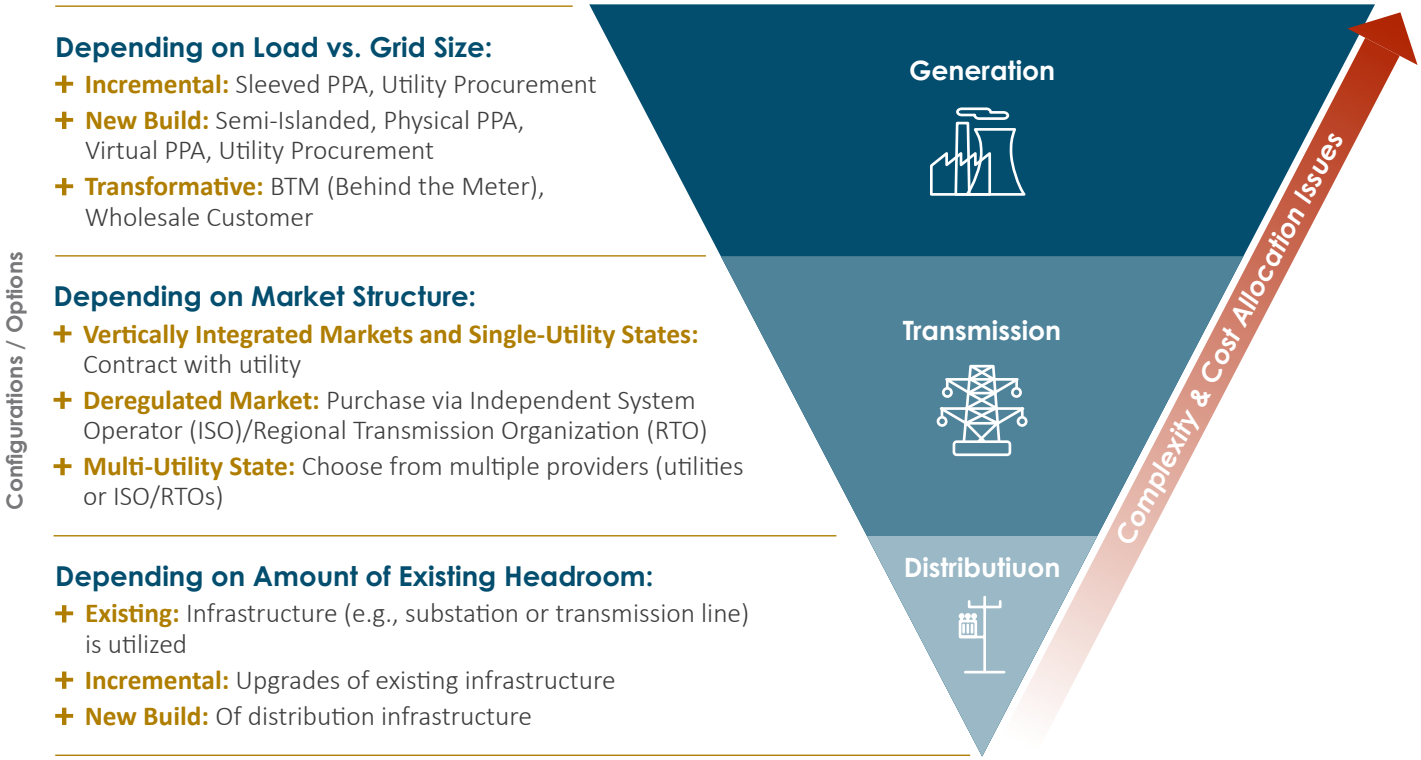


Figure 7 provides a deeper dive into each contracting option or "archetype". The figure outlines each of the option's main tenets, applicability based on market type, and potential relevant archetypes/use cases, which are meant to serve as examples and should not be seen as limiting. There is a wide spectrum of options, including both traditional and emerging archetypes, ranging from fully off the grid on one end to cost-of-service ratemaking under an existing industrial tariff on the other, and many options in between. The list is sorted by utility involvement and indicates the varying levels of utility service from partial (indicated by tilde) to full (indicated by check mark).

Figure 7. *Spectrum of Rate and Contract Design Options, based on Load Considerations Archetypes*

Contracting Options	Definition	Utility Service	Applicability		Load Size Relative to Grid	Use Case
			Vertically Integrated Markets	Deregulated Markets		
Behind-the-Meter Contract	Load co-located with generator, islanded/off-grid		✓	✓	New Build or Transformative	Relatively rare given siting barriers; largely only seen in markets with grid constraints & fast go-to-market needed
Wholesale Customer	Transmission-level customer with minimal utility service	~	✓	✓	Incremental, New Build or Transformative	Expected to become more common as size of load grows
Physical PPA	Customer contracts with developer for physical power, utility provides T&D	✓		✓	Incremental, New Build, New Build, or Transformative	Can help customer improve speed to market, provide cost stability and meet clean energy targets
Virtual PPA	Customer contracts for renewable energy credits with no physical delivery	✓		✓	New Build	Tool for customers to meet clean energy targets
Sleeved PPA	Utility is intermediary, contracting and delivering power from a third-party generator to the buyer	✓		✓	Incremental	Can be a bridge solution (e.g., with on-site generation) to transition to full wholesale market access or utility service
Semi-Islanded/Non-Firm Service	Interruptible service, supplementing with on-site generation permanently or as a bridge solution	~	✓	✓	New Build	For customers that value speed to market, can be flexible or leverage on-site generation
Ring-Fenced Commercial Structure	Utilities isolate the customers, procuring effectively separate resource portfolios and charging marginal cost	✓	✓	✓	New Build	Relevant for smaller utilities incorporating larger loads to insulate ratepayers from potential cost-shift. Historically most used by public power utilities
Rolled-in Incremental	New infrastructure costs are rolled into existing rate structure and thus spread across all customers	✓	✓	✓	Incremental	Can be beneficial to other ratepayers by putting downward pressure on rates but need to de-risk and regularly update cost allocation factors

Figure 8 compares these archetypes with varying tradeoffs across cost, benefits, risk and flexibility. One key theme throughout the archetypes is the tradeoff between risk mitigation and shared benefits, as they are on opposite ends of the spectrum, presenting an inherent tradeoff. On one end, the large loads could be in a separate rate class (or off grid at some level, such as totally islanded vs. semi-connected with the grid as "backup"), posing little to no risk to other ratepayers. But the utility forgoes potential benefits that can only be generated if the large load is included in the broader pool of customers, such as by applying the positive margin (i.e., revenues above its marginal cost of service) collected towards existing system costs. Depending on its priorities, utilities must assess the risk-benefit tradeoffs to inform under which conditions to include large in a broader pool of customers to allow for shared benefits versus isolate the load, such as using a separate rate class, to protect existing customers. To demonstrate the tradeoffs, Figure 8 illustrates the spectrum of contracting options according to these key criteria, with green indicating a high score, yellow indicating a medium score, and red indicating a low score.

Some of these archetypes will be more appropriate to future growth than others. For example, although rolled-in incremental rates – a common rate design approach – scores high in the matrix, it will likely be limited to an interim solution. As large loads start to become a large share in both peak and average demand of the local interconnecting utility, the tension between traditional utility frameworks and this unprecedented load growth will accelerate. Alternatives, such as the Wholesale Customer archetype, may become increasingly relevant.

Figure 8. *Comparative Matrix of Archetypes*

Contracting Options	Promotes Data Center Growth	Relative Risk Burden		Protects Existing Customers	Shared Infrastructure Needed	Potential Ratepayer Benefits	Relative Ease of Implementation
		Utility	Developer				
Behind-the-Meter Contract			✓				
Wholesale Customer			✓				
Physical PPA			✓				
Virtual PPA			✓				
Sleeved PPA		✓					
Semi-Islanded/Non-Firm Service			✓				
Ring-Fenced Commercial Structure			✓				
Rolled-in Incremental		✓					

High score Medium score Low score

Archetype Deep Dive: Wholesale Customer

The "Wholesale Customer archetype" is an emerging option in which large loads have the flexibility to procure electricity directly from the wholesale market, minimizing reliance on the utility for supply. This model is particularly relevant where the load's relative size is significantly larger than the interconnecting grid (i.e., "Transformative"), shifting much of the cost and risk to the utility, which simply serves as an intermediary to the wholesale market. This option is not applicable for sub-transmission developers (e.g., smaller data centers more representative of the current fleet averaging 25 to 50 MW) or markets without an Independent System Operator (ISO) or Regional Transmission Organization (RTO). But this option has worked in the past and can be more widely adopted in the future with enabling reforms.

This option can provide benefits to both the large load and the utility. On the load side, the customer has significantly more flexibility, such as in renewables procurement, and the opportunity to reduce costs, which will become increasingly important in the future; data centers are currently relatively price insensitive in the race to build out new infrastructure but will eventually need a cost-effective path forward to continue growth. Moreover, on the utility side, this option shifts away the cost and risk, especially as the utility is not obligated to provide generation service like in retail choice markets.

This archetype has been used in the past during times of growth, such as for aluminum smelters that were direct-service customers of Bonneville Power Administration, bypassing intermediates like utilities or state regulation, and it is now starting to re-emerge. For example, Rappahannock Electric Cooperative (REC) submitted a proposal similar to this archetype but was ultimately rejected by the Virginia regulator, the State Corporation Commission (SCC). The proposal outlined the creation of a subsidiary called "Hyperscale Energy" which would have included several subsidiaries registering as load-serving entities that would procure power for individual data center customers, while REC would only provide the physical infrastructure and retail services, effectively buffering other ratepayers from risk.[20]

When evaluating this option in Figure 8, this archetype scores well for protecting existing customers and promoting data center growth, but scores poorly for relative ease of implementation given the required reforms to enable this option nationally. Currently, this archetype could work well in the Electric Reliability Council of Texas (ERCOT) region given its market structure. But in Midcontinent System Operator (MISO) territory and other RTOs without established processes for large load interconnections, significant regulatory reforms would be required, alongside improvements to speed of market. More broadly, in markets with retail access, the implementation of this approach could be relatively straightforward; in areas without, the focus would need to shift towards securing virtual retail access to prevent cost-shifting. Another potential obstacle could arise from utilities, who may resist relinquishing the opportunity to expand their rate base, thus presenting a challenge to widespread adoption.

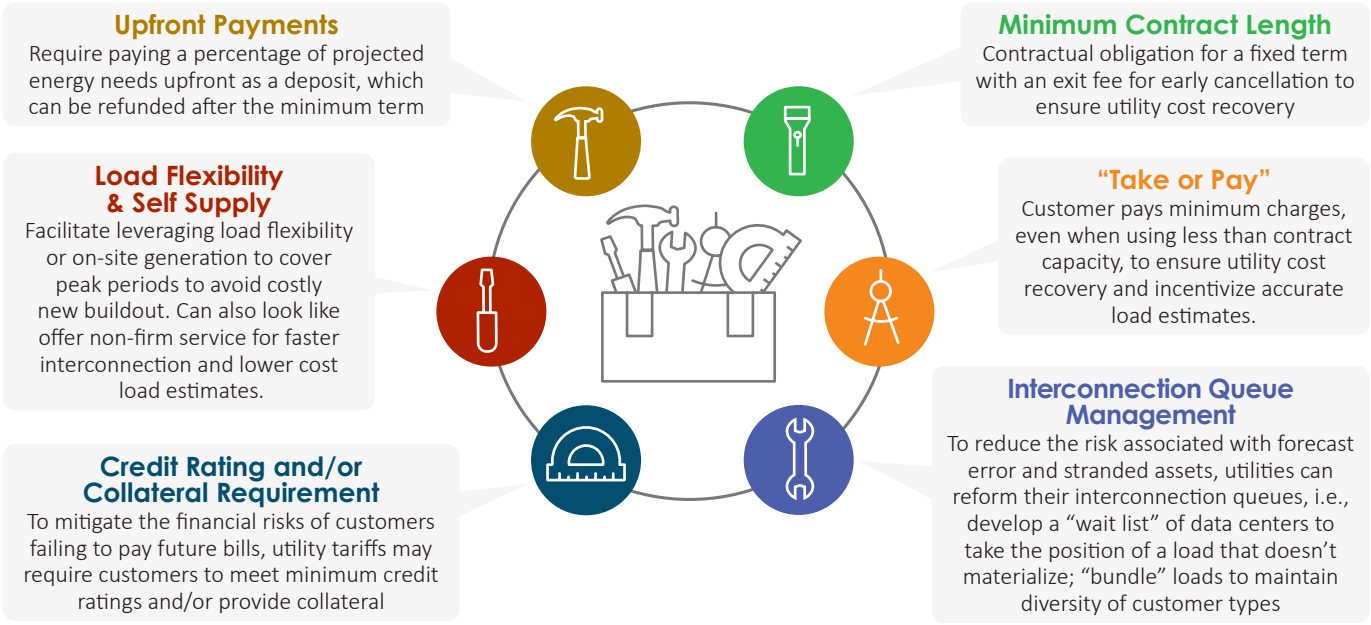
This archetype is worth enabling as it will only become increasingly relevant in the future if loads reach transformational sizes; it will be more effective for them to be in their own pool or independently procuring their resources to more appropriately balance cost and risk. More broadly, it is important to develop a bridge to a future where large loads can have more flexibility and responsibility in procurement, which can reduce risk and impacts to ratepayers.

[20] Allsup, Maeve. 20 December 2024. "To get data centers online, one Virginia co-op is proposing a new business model." Latitude Media. https://www.latitudemedia.com/news/to-meet-massive-data-center-load-one-virginia-electric-co-op-is-proposing-an-entirely-new-business-model/

Risk Mitigation Toolkit

As previously discussed, large loads can pose risks if not effectively managed, making it crucial to layer risk mitigation strategies on top of the archetypes. These risk mitigation mechanisms are essential components of the rate design framework in allocating cost and risk. In particular, the Virginia SCC highlighted these as the "key [large load] tariff issues," underscoring the importance of exit fees, collateral provisions, minimum bills, contract durations, and direct cost assignments.[21] Figure 9 below illustrates these as mechanisms assembled into a "toolkit," as tariffs often use a combination of these tools (as displayed in Table 1 and the Appendix).

Figure 9: *Risk Mitigation Toolkit*



Given the current uncertainty in data center load growth, these mechanisms should be incorporated into today's tariffs, but it is important to understand that risk mitigation is a tradeoff with the opportunity to generate shared benefits, such as downward rate pressure. Risk mitigation should be balanced with other priorities (e.g., economic development and shared benefits) and the perceived risk from the data centers' perspective (e.g., utility failing to interconnect on schedule) as well as avoid being punitive or discriminatory. This balance can be a point of contention, with disagreement over specific terms and rates from various stakeholders including utilities, regulators, ratepayer advocates, and industry representatives, despite the concept of risk management having shared support. In the long term, as the industry matures and uncertainty abates, utilities could place less emphasis on risk mitigation and consider incorporating these loads back into the broader pool to generate shared benefits.

[21] "Scheduling Order and Notice of Technical Conference." 02 October 2024. Commonwealth of Virginia State Corporation Commission. https://www.scc.virginia.gov/docketsearch/DOCS/81_m01!.PDF

Transmission

Another key aspect of electricity costs and rate design is transmission and interconnection costs, which address different aspects of grid infrastructure and cost responsibility. Transmission costs relate to the shared high-voltage network that moves electricity over long distances and are typically allocated across many users. Interconnection costs, on the other hand, are the direct expenses of physically connecting a new customer or generator to the grid at a specific point, and they vary depending on the project's location, size, and complexity.

Transmission Cost Allocation Issues and Key Considerations

Cost allocation for shared transmission (existing and new) has historically been one of the most challenging issues in rate design and is not a new issue nor one caused by large loads in isolation. The cost allocation process is difficult due to the nature of how transmission infrastructure is used and funded. Transmission systems are typically designed and operated for broad public use, often involving multiple states, utilities and customer types. Costs are generally shared among all users based on a combination of capacity (usually based on user peak demand during certain time periods) and/or energy use. Additionally, the long-term nature of transmission investments complicates the assessment of who benefits from the system over time, often leading to questions over whether costs should be borne by new load, all users, or a mix of both.

Transmission cost allocation for new large loads can become challenging in this context, which can raise issues around how such customers should be charged to access and utilize the existing transmission network as well as support its continued expansion. For example, key questions include: How much should the customer contribute to support the existing transmission network across various usage profiles especially if behind-the-meter generation is used? How should it pay for transmission upgrades and expansion especially on a broader regional basis? If a retail customer, how should the customer be charged for ancillary services?

Generally, a cost-causation principle has been used in the past, where costs are allocated based on who (i.e. specific customers and/or broader customer classes) causes the need for additional transmission capacity or upgrades. Even as individual new loads pay their "fair share" (under normal ratemaking practices), the need for continued infrastructure (arising from sustained demand growth) can impact all ratepayers as total system costs increase.[22]

The right allocation depends on several factors and there is no "one size fits all" ideal formula, but it is essential to recognize that there is risk and that strategies should be used accordingly to manage the risk. Some key considerations to include are:

- Incorporate flexibility to recognize that infrastructure built initially to serve one or a handful of large loads may ultimately provide broader benefits and be used by other loads as well. One such approach could be creating mechanisms to credit or refund costs once these benefits are identified and quantified, which has been standard practice for large loads in many jurisdictions.
- Regular updates of cost allocation factors to help prevent ratepayer impacts especially as system conditions evolve and given the faster pace of load growth.
- Use long-term integrated system planning to account for future growth, system reliability, and clean energy targets on a regional level can help preemptively identify infrastructure needs and better distribute costs.

[22] Analysis and more detail on how broad market shifts driven by load growth can impact total grid infrastructure costs and cost allocations is outside the scope of this study but is explored in more depth in E3's JLARC study: Energy and Environmental Economics. "Virginia Data Center Study: Electric Infrastructure and Customer Rate Impacts." https://jlarc.virginia.gov/pdfs/presentations/JLARC%20Virginia%20Data%20Center%20Study_FINAL_12-09-2024.pdf

Interconnection Cost Issues and Key Considerations

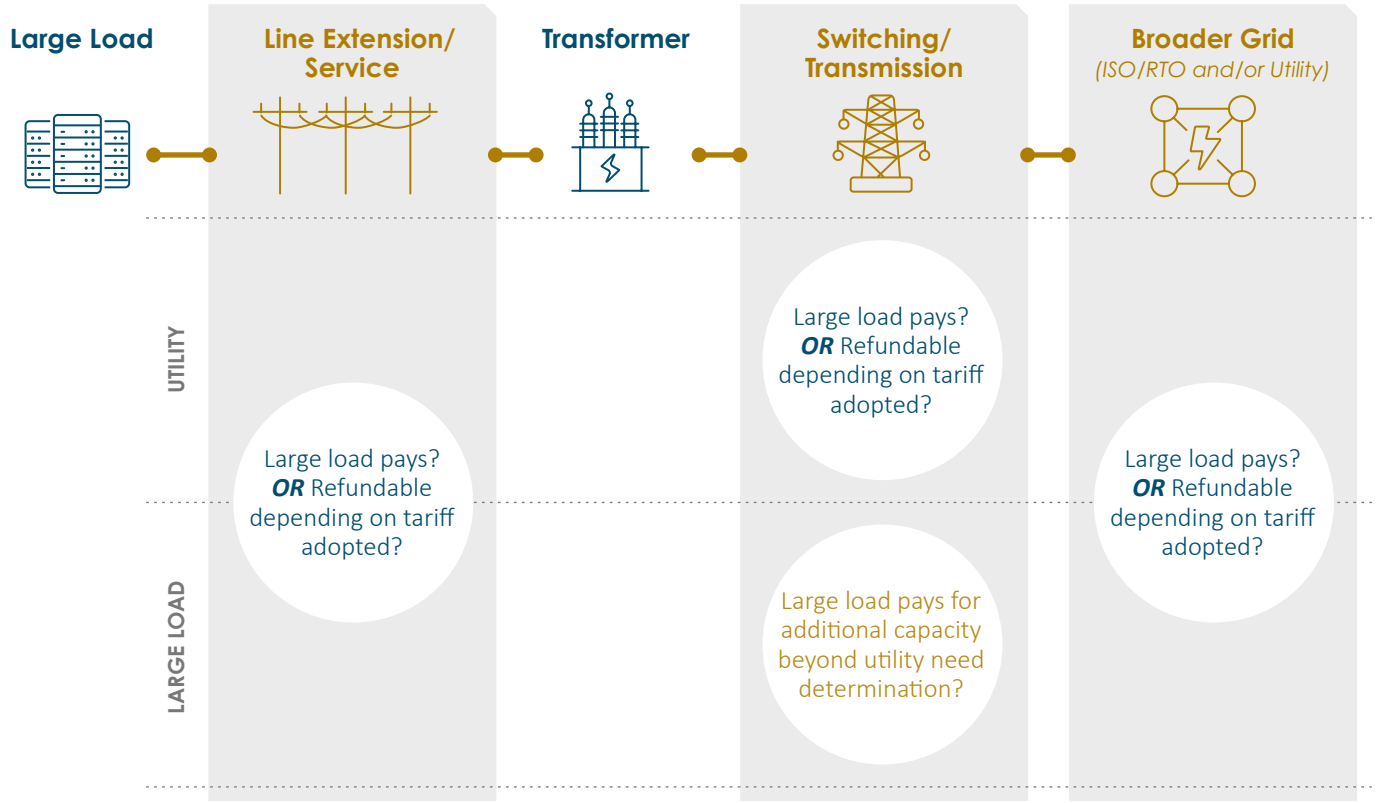
Interconnection Cost Allocation

In addition to electric retail rate charges, there may also be fees for interconnection, particularly for large customers like data centers. These costs- often in the form of long-term revenue commitments, Contribution in Aid of Construction (CIACs) or alternatives- can be set by the interconnecting utility but also be subject to regional tariffs in areas managed by ISOs and RTOs. Moreover, there can be significant uncertainty around interconnection cost responsibilities and a range of how utilities allocate the costs as displayed in Figure 10.

Line extensions refer to extending the utility's distribution or higher voltage transmission network to connect a new customer. These costs can be borne by the customer or allocated by the utility via line extension allowances, recognizing that load growth can bring beneficial ratepayer impacts. For example, Mississippi Power pays for the line extension up to a maximum cost-to-revenue ratio.[23] For commercial and industrial customers, the ratio is 3 to 1, where the customer must pay for any costs in excess of three times the expected annual electric revenues collected by the utility. PacifiCorp had a similar structure, where customers receive an extension allowance equal to two times the estimated annual revenue; however, for "large, complex, or speculative" extensions, the customer had to advance the utility's estimated costs, with an option for a refund in later years if the new infrastructure provided broader system benefits.[24]

As previously discussed, uncertainty is costly to all parties and transparency and standardization should be implemented where possible. The cost allocation structure should be clear and balanced across stakeholders, ensuring costs are shared fairly among all projects benefiting from upgrades.

Figure 10. *Uncertain Interconnection Cost Responsibilities*



[23] "Line and Service Extension Policy." Mississippi Power. https://www.mississippipower.com/content/dam/mississippi-power/pdfs/business/pricing-and-rates/rules-regulations---service-policies/Line_and_Service_Extension_Policy.pdf

[24] "Rule 14: General Rules and Regulations – Line Extensions." https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/washington/rules/14_Line_Extensions.pdf

Interconnection Process Issues and Improvements

The current large load interconnection process and its lengthy queues are another major driver of costs for both customers and utilities. A major factor is the "first come, first served" process which can be inefficient especially given the likely double counted loads and long tail of speculative loads, as discussed earlier in the paper. Given this structure and the utility's obligation to serve, the utility and/or interconnecting ISO/RTO studies all requests equally and sequentially or in batches, leading to inefficiencies and delays. Moreover, the current piecemeal approach to interconnections – where each new facility is treated as an isolated case – often fails to account for the cumulative and systemic impacts of these large loads. Utilities and grid operators may struggle to capture the combined effects of these loads and associated infrastructure upgrades, leading to potential ratepayer impacts due to the lag in adjusting rates.

Generation interconnection faces some analogous issues and congestion, which adds to the system constraints and long lead times faced by large loads. These barriers must be removed to bring new generation online faster for both behind-the-meter and front-of-the-meter solutions. Although not a focus of this paper, addressing generation side constraints would help manage and take pressure off of the cost impacts from new loads and rate design. If the supply side is flexible and sufficient, responding quickly to demand side signals, then managing large electric loads becomes significantly simpler and more efficient. However, if there is a structural constraint on supply, like there is currently, balancing the dynamics and impacts becomes much more challenging.

Both processes could benefit from similar reforms such as:

+ **Cluster Approach** where multiple projects in the same region or time frame are evaluated simultaneously, reducing redundancy and improving efficiency by assessing the potential for shared infrastructure needs collectively and minimizing piecemeal upgrades.
+ **"Fast Track"** or expedited process for projects with minimal system impact or align with strategic goals. For generation, these could include new assets that significantly address grid reliability and/or decarbonization goals. For large loads, this could look like jumping to the front of the queue for non-firm connection. Moreover, there could be a tranche process where customers sign up for non-firm service and move ahead if a project drops out, similar to an early admission process.

However, queue reform is unlikely to be a panacea. For example, Bonneville Power Administration reformed its process but its queue has been inundated with requests, leading the agency to freeze its process and consider additional measures to filter out speculative or unrealistic requests.[25] A critical complementary strategy could be an improved upfront cost allocation process, in which the customer bears the costs of studying, planning and serving the load at the start of the development cycle, in addition to meeting other project-readiness indicators (e.g., securing land rights, demonstrating permits) to form a "first ready, first funded, first served" process.

More broadly, long-term planning should be better integrated by reflecting the mutual obligation between utilities and customers and aligning transmission planning with interconnection to more effectively anticipate and prepare for high growth areas. For large loads, this could include meeting with customers and other stakeholders to forecast demand more accurately. For utilities, it should include more clearly defined commitments on when to serve the load, rather than relying on an "as ready, when ready" approach. For generation, this could include improving modeling tools and coordination between RTOs, ISOs, and utilities. These alternatives could expedite timelines and reduce costs, improving the current interconnection bottleneck on both the generation and demand side, in addition to helping attract economic development.

[25] Nilsson, H. (2025, September 5). BPA transmission pause questioned during workshop. RTO Insider. https://www.rtoinsider.com/114209-bpa-questioned-during-workshop-on-tx-planning-pause/

Key Considerations for Designing Rates and Tariffs for Large Loads

Building on the overview of different types of large load growth, rate design options, and key risk mitigation tools, this section concludes with a set of overarching best practices for utilities and regulators to consider when designing rates and tariffs for large loads.

1. Charge Data Centers At Least Marginal Cost to Protect Ratepayers

Charging data centers at least marginal cost will help ensure no customer cross subsidization. To generate surplus utility revenue, data centers can be charged a portion of non-marginal, or fixed, costs as well, which could lead to a range of equitable outcomes, including putting downward pressure on rates. In some cases, utilities may intentionally charge below marginal cost to attract economic development, accepting a degree of cost recovery tradeoff in part of a broader policy decision. Figure 11 below illustrates the range of potential cases, and the expected impact on costs for other classes.

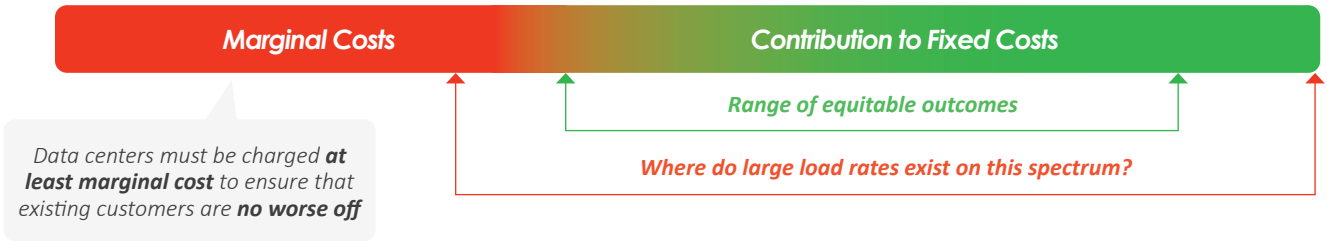
2. Identify and Manage Risks Proactively

As discussed previously, large loads are not homogenous and the appropriate risk mitigation tools to implement depend on factors including the load size and demand profile, time to interconnection, financial strength, and likelihood of materializing. Given uncertainty in data center load growth, tariffs should balance risk management mechanisms with other priorities (e.g., economic development and shared benefits), the perceived risk from the data centers' perspective (e.g., utility failing to interconnect on schedule), and avoid being punitive or discriminatory. While risk management has broad support, disagreement over specific terms and rates from various stakeholders including utilities, regulators, ratepayer advocates, and industry representatives will persist. For this reason, detailed assessment of the full range of benefits, costs and potential risks of the new loads in specific markets will be important.

As discussed in greater detail below, risk mitigation must be balanced with the opportunity to generate shared benefits. Although these risk mitigation mechanisms, such as those outlined in Figure 9, are essential to today's rate designs given the current uncertainty, in the long term, as the industry matures and uncertainty abates, utilities should place less emphasis on risk mitigation and consider incorporating these loads back into the broader pool to generate shared benefits.

Figure 11. Range of Cost Recovery Outcomes

Cost Recovery Outcome	Notes	Impact on Costs for Other Classes
Revenue < Marginal Costs *The utility does not fully recover marginal costs.*	May be perceived as inequitable, as costs for other customer classes would increase but may be acceptable in the context of economic development.	↑
Revenue = Marginal Costs *The utility exactly recovers marginal costs.*	May be perceived as equitable.	↔
Revenue > Marginal Costs *The utility recovers marginal costs plus a fair allocation to non-marginal costs.*	May be perceived as equitable.	↓
Revenue >> Marginal Costs *The utility recovers more than marginal costs plus a fair allocation to non-marginal costs.*	May be perceived as an inequitable "overcollection" that benefits other customers at the expense of new data centers.	↓↓



3. Facilitate and Incentivize Load Flexibility

Load flexibility can provide significant value to the grid and generate ratepayer savings. Although not all data center load is flexible, data centers typically build on-site generation for reliability, which could be leveraged and configured to provide demand reductions, reduce the level of requested capacity, and increase grid resilience in certain circumstances. Participation would have to be enabled and incentivized via rate design or programs and could be treated similarly to microgrids by having the on-site generation to serve as available capacity for resiliency during emergencies. Other incentives could include faster interconnection and/or a reduced rate, such as non-firm/standby service, though using fossil fuels could undermine local air pollution compliance and emissions goals.

More broadly, meeting the grid where it stands today can be an important cost-effective principle, especially in considering the unique nature of data centers in their willingness to pay for clean energy and propensity to build on-site generation for reliability. Given that meeting energy needs is easier than meeting capacity needs, data centers could get nearly all of their energy needed from the bulk system, such as via a non-firm or interruptible utility service, and absorb excess renewable generation; the remaining tail risk could be covered with load flexibility, on-site generation, behind-the-meter and/or front-of-the-meter contracts, plus the direct assignment of any applicable, new or existing, costs. This arrangement could be more cost-effective, lead to faster interconnection, and improve clean energy integration, as outlined in the Archetypes section.

4. Incorporate Transparency

Transparency in electricity rate design and the interconnection process is crucial for all parties to foster fairness and predictability, enabling customers to make informed investment decisions and stakeholders to understand cost impacts. When there are no explicit guidelines, there can be inefficiencies and regulatory uncertainty, leading to higher costs and risks. Transparency becomes even more important in the context of unprecedented demand growth and significant uncertainty. PG&E's proposed Rule 30 is an example of a transparent framework that outlines how customers are billed and how transmission and distribution costs are allocated.[26]

However, transparency can be more engrained in certain jurisdictions than others, namely large utilities with significant large load growth that need a clear and scalable process. Smaller utilities often use the tool of bilateral contracts, which is a direct and generally confidential agreement between the utility and large customer that outlines the terms of electricity supply, pricing and delivery. Although less transparent, this tool can provide a flexible and efficient path forward in certain contexts.

5. Prioritize Adaptability and Flexibility

Uncertainty is inherent with new large load growth and more innovative and flexible approaches will be needed to reflect and mitigate the risk associated with this uncertainty. New large loads, utilities, and power producers are all innovating with new technologies, regulatory constructs, and contract/financing structures. From the customer side, adaptability or optionality should be a feature of the tariff design that enables benefits to both new large loads as well as the utility/ratepayers without being overly prescriptive. For large loads, the key factors are customer choice (such as in energy sources and new technologies) and innovation (such as in demand flexibility and the use of on-site generation).

Regulators and other decision-makers should be open to exploring alternative structures to finance and derisk new infrastructure costs. Given the accelerating pace and scale of load growth, novel structures are needed, in particular those that are robust enough to operate under unpredictable cycles, ranging from sustained growth to boom-and-bust dynamics to periods of rapid expansion followed by slowdowns or pauses. For example, some tariffs can incorporate flexibility such as by outlining terms under which customers can adjust their contracted capacity and energy obligations by selling unused capacity to other customers, such as after a fixed number of years or when exiting the system; examples are provided in the Appendix. Moreover, "contract" structures can accommodate more flexibility and innovation versus a more traditional rigid rate design, and allowing tariffs to function more like contracts is an important best practice.

Moreover, instead of attempting to create long-term solutions for the next 30 years, regulators should focus on establishing frameworks and rates that can handle near-term challenges, such as with a fixed term (i.e., up to a certain amount of GW of new connection or over a set amount of months or years). This approach would be more nimble, by creating offramps that can help manage unforeseen risks and evolving market conditions.

[26] Pacific Gas and Electric Company. 21 November 2024. "Application for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service." https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2411007/7851/547330908.pdf

Data Center Rate Design in Practice: Case Studies

Overview

The goal of the case studies is to quantitatively evaluate how individual data centers in practice are benefiting or costing communities. E3 evaluated data centers in four different utilities to capture a range of geographies, market structures, and business models. The utility territories included were:

- Pacific Gas & Electric in California
- Umatilla Electric Cooperative in Oregon
- Dominion Energy in Virginia
- Entergy in Mississippi

For each region evaluated, E3 used a cost-benefit framework to evaluate the extent the Amazon data centers imposed new costs (such as any new required investment in new electricity generation, transmission and distribution infrastructure), compared to the revenue generated (i.e., through Amazon bill payments), and assessed the delta in 2025 and 2030. Any surplus revenue (i.e., revenues exceeding costs) suggest potential ratepayer benefits, such as downward rate pressure. This analysis evaluated Amazon data centers in isolation, without modeling underlying system changes to supply and demand. These findings are contingent on the stated assumptions, Amazon-provided data, and public utility data; any changes to these inputs could significantly change results.

Methodology and Key Data Sources

Using a cost-benefit framework, E3 compared the data centers' levelized projected costs to the annual projected revenues. The analysis then assessed the resulting delta:

- If revenues exceed costs, then surplus revenue[27] is generated, which could provide a potential benefit to ratepayers, such as downward rate pressure. While the use of this additional margin is at the utility's discretion and subject to regulatory approval, if no action is taken, the additional margin naturally reduces rates as the utility needs to collect less revenue from customers.
- If costs exceed revenues, then the new load may increase rates for other ratepayers.

To develop these quantitative estimates, E3 used data provided by Amazon and public utility data, including published cost of service studies and rate schedules, and filled in gaps with generic assumptions as needed.

Load Characteristics

For the data centers evaluated in each region, E3 modeled the average hourly data center load over the course of 2025 and 2030. Amazon provided load size and typical load profiles for the data center facilities and when data was unavailable, a representative hourly load profile was used and applied across all hours of the year.[28]

Utility Revenues *(i.e., Amazon bill payments to utility)*

Utility revenues reflect the customer payments to the utility to recover its revenue requirement. In terms of data sources, the model used the utility-specific tariffs that best aligned with the bills Amazon data centers currently pay in each region. As a benchmark, the modeled revenue estimates were compared to actual historical bills and contracts for the existing data centers, where data was available. Below are the main charge categories used to present the study results:

- **Demand Charge:** Demand charges recover costs that are linked to the customer's peak electricity usage within a given period. These are generally billed on a $/kW basis.
- **Energy Charge:** Energy charges recover costs that relate to total energy consumed by the data center (e.g., fuel costs) and are based on total energy sales on a $/kWh basis.
- **Customer Charge:** Customer charges recover fixed costs that do not vary with usage or demand, such as customer service or meter costs. These are typically billed on a $/month basis.

[27] Surplus revenues are defined as revenues above the utility's estimated cost to serve, where that cost reflects new fixed infrastructure costs, variable operating costs, depreciation of the existing infrastructure, taxes, and a return on utility investment.

[28] Gerke, B. et al. (2020). The California Demand Response Potential Study, Phase 3: Final Report on the Shift Resource through 2030.Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/california-demand-response-potential

For the 2025 case studies, existing rate structures were used to model utility revenues. For the forward-looking 2030 case studies, these rates were extrapolated by growing generation capacity and energy related components in line with forecasted price increases (e.g., location-specific wholesale price forecasts); all other components increase with projected inflation.

Utility Costs to Serve the Data Center

Cost Categories

The modeled costs reflect the utility's estimated costs to serve the data center load. Below are the main cost categories used to present the study results.

- **Marginal Generation Energy Costs:** Also known as "production energy costs" or "system lambdas", these are the volumetric costs to serve an additional kWh of load. These are generally variable costs to reflect fuel consumption and variable operation and maintenance (O&M) costs.
- **Marginal Generation Capacity Costs:** Also known as "production demand costs", these are demand-driven costs to serve an additional kW of load. These generally include the fixed costs for generation resources, such as CapEx and fixed O&M costs.
- **Marginal Distribution Costs:** These are costs related to the distribution infrastructure used to serve the data center. Although data centers are modeled with transmission-level interconnection, some utilities include funding for public-good programs into the distribution component of rates for large loads, which all customers must pay.
- **Marginal Transmission Costs:** These are costs that are related to the transmission infrastructure used to serve the data center.

Note that the costs modeled in the case studies include the utility's implied rate of return, so any surplus revenue generated could be used to offset the revenue requirement for the customer class, effectively reducing the cost burden for those other ratepayers.

The model excluded costs for infrastructure exclusive to the Amazon facility that Amazon pays for upfront (e.g., dedicated distribution substations or transmission lines) as these costs are simply passed through and would not have a ratepayer impact.

Cost Scenarios

For the 2025 cases, E3 examined the near-term impact of data centers by using marginal costs to serve incremental demand (generally with existing infrastructure or headroom).

For the 2030 cases, E3 investigated the potential cost and benefit impacts where overall load growth has driven new generation and transmission buildout, referred to as the "new build" cases. E3 modeled two bookend cost scenarios, reflecting two different supply mixes:

- A "Least Cost Firm" New Build case, for which the entirety of the data center's load is served by a new firming generation resource (i.e., the marginal cost resource).[29]
- A "Least Cost Firm and Solar" New Build case, where specifically new least cost firm and solar capacity are installed in equal amounts to the data center's peak load. For example, for a 50 MW data center, 50 MW of solar and 50 MW of the least cost firm resource were modeled.

In terms of data sources, the near-term costs were generally derived from utility-specific data (such as the utility's cost of service study, prior E3 studies, Amazon data, or other public data). For the mid-term cost estimates, E3 leveraged a mix of utility-specific data and in-house models. Where utility-specific generation cost data was unavailable, E3 used its RECOST model to estimate generation costs. RECOST is based in public data sources including from the National Renewable Energy Laboratory, Energy Information Administration, Pacific Northwest National Laboratory, etc.[30] Given a mix of technology-specific assumptions for system performance and operations, upfront and ongoing costs, and financing parameters, RECOST computes levelized cost metrics for the resource mix, such as the levelized fixed cost (LFC, $/kW-yr) and levelized cost of electricity (LCOE, $/MWh). Where applicable, transmission and distribution costs were drawn from public estimates or Amazon data on project costs.

[29] This analysis assumes new natural gas generation as the marginal cost resource, which is typical in most markets. This serves as a conservative cost proxy as in reality, a mix of existing and new resources would be used. The resource mix would also likely vary by region, including a combination of wind, solar, battery storage, or natural gas. But this simple approach strikes a balance between precision and accuracy, given data availability and the scope of this analysis.

[30] Energy and Environmental Economics. RECOST Model. https://www.ethree.com/tools/recost-model/

A Note on Analysis Vintage

Since the original analysis was completed, some cost drivers have shifted in ways that may impact the economics of serving large loads, but we broadly expect the results of the analysis to remain directionally the same.

- Distribution equipment costs have risen sharply heading into 2025 due to nationwide demand and supply-chain constraints. However, in the case studies examined, these costs are generally passed through and borne upfront by Amazon and thus have no impact on this analysis.
- Fuel prices have increased but are commonly passed through to Amazon (this may vary regionally depending on whether Amazon has procured renewable generation) and therefore do not materially affect utility surplus revenues or other rate classes.
- Costs of new build generation capacity have been rising due to new federal import tariffs, equipment price escalation, and the expected phase-out of federal tax credits for wind and solar, which may increase the cost of serving new load depending on how much new build is required.
- Market capacity prices have also surged in some regions (e.g., PJM's 2025 auction), which directly impacts data centers on market-based rates; for those on general service tariffs, utilities may need to update rates to ensure proper cost recovery, though this issue is not unique to large loads. Some tariffs, like Dominion's Market Based Rate[31], are structured to have large loads directly pay these costs.

Results

In each of the studied utility regions, E3 found the Amazon data centers are expected to generate either sufficient or surplus revenue, implying a neutral impact or potential benefit to utility ratepayers in 2025 and 2030, given current rate constructs. None of the utility regions showed negative revenues (i.e., subsidies). This finding indicates that existing rate policies have been sufficient in preventing cross-subsidization of data centers by existing ratepayers. E3 intentionally examined a diverse subset of Amazon data centers that represent a wide range of sites, regions, and market structures. The average ratepayer impact by scenario is outlined below.

Beyond potential financial benefits, several of the evaluated data centers illustrated some of the innovative structures discussed above, such as self-supplying generation and novel financing arrangements. These structures can help streamline timelines, improve local reliability, support critical carbon-free resources, and derisk emerging technologies critical to the clean energy transition. Moreover, they demonstrate varied approaches to risk sharing between the utility and customer while still maintaining protections for the utility and its ratepayers.

In 2025

- The evaluated data centers are expected generate surplus revenues of **$33,500/MW**.
- Assuming a typical data center is 100 MW, this implies a potential ratepayer benefit (such as downward rate pressure) of **$3.4 million** per data center.

In 2030

- The surplus revenues are projected to be **$60,650/MW** in the "Least Cost Firm" scenario, and **$33,250/MW** in the "Least Cost Firm and Solar" scenario.
- Assuming a typical data center is 100 MW, this implies a potential ratepayer benefit (such as downward rate pressure) of up to **$6.1 million** per data center.

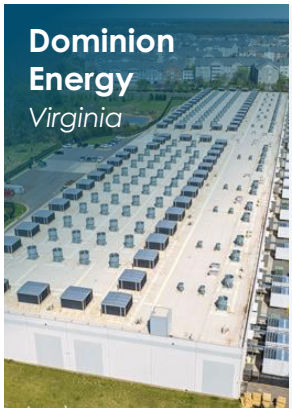
[31] Additional information on this tariff is included in the Appendix.

Qualitative Findings

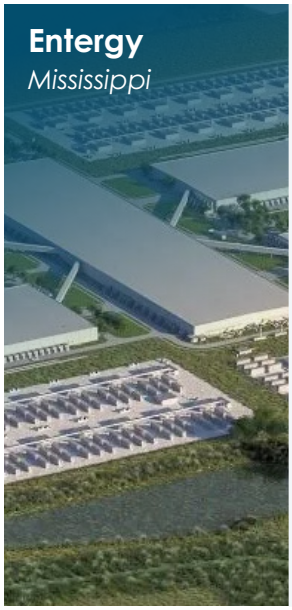
E3 also identified qualitative findings in its review of the case study regions. These findings further support and illustrate the benefits of large loads outlined earlier in the paper, including the downward rate pressure dynamic and broader grid benefits. They also provide additional detail on how these benefits manifest across each specific utility territory.

As of May 2025, PG&E is anticipating 8.7 GW of data center load, up significantly from 5.5 GW at the end of 2024.[32] The utility expects this growth to benefit customers, estimating that each additional gigawatt of data center demand could reduce average customer monthly bills by 1 to 2% over the long term. These savings are generated from data centers enabling PG&E to better utilize its existing infrastructure and spreading its fixed costs over a larger volume of sales, a dynamic described in the Rate Design Options section.

Amazon has partnered with Umatilla Electric Cooperative (UEC) in an arrangement that allows it to procure its own energy supply. Through this arrangement, Amazon can purchase carbon-free energy to power its data centers, which can generate benefits such as expanding local clean energy capacity, enhancing grid resilience, and supporting broader decarbonization goals.



Dominion Energy in Northern Virginia, home to the world's largest data center market, has shared how load growth can help maintain affordability for its customers most recently in its 2025 biennial rate review. In its submitted testimony, the company describes the downward rate pressure dynamic noting that "incremental revenue from data center load helps cover a utility's fixed costs… while these customers may require up-front capital investment, over time these assets will depreciate… and their incremental revenue should lower system average costs, providing opportunities to fund new investments and reduce rate pressure." The company also observes that data centers improve utilization of existing infrastructure with "their stable load profile increas[ing] off-peak usage of grid assets that would otherwise be underutilized, enhancing efficiency and cost-effectiveness."[33]



Entergy Mississippi has discussed its partnership with Amazon at length, underscoring both grid modernization and downward rate pressure benefits. In a July 2025 op-ed in the Magnolia Tribune, Entergy Mississippi CEO Haley Fisackerly highlighted the company's need to modernize its grid, noting that "roughly one third of our power generating facilities [are] at or near retirement age."[34] Fisackerly further emphasized that the associated costs "would have fallen on a stagnant customer base, with more than 20% of our customers at or below the national poverty level." Entergy Mississippi has worked to recruit Amazon over several years in partnership with the State of Mississippi and with clear conditions: "Amazon must not harm our existing customers" and the energy price charged to Amazon must "provide other customers with an economic benefit."[35]

In line with these commitments, Amazon will not only cover the cost to serve its load but also fund nearly 50% of grid improvement costs that would otherwise have impacted residential customer bills.[36] These investments provide Entergy Mississippi ratepayers with tangible benefits, including a slowdown in rate increases. While the company had previously forecasted annual growth rates of 8 to 10%, it now expects a more moderate trajectory of 3 to 4%. Customers also did not see a rate adjustment this year due to Amazon provided revenue.[37]

[32] Pacific Gas and Electric Company. "Surging Data Center Growth to Help Lower Energy Costs for PG&E Customers." PG&E Investor News, 27 May 2025, https://investor.pgecorp.com/news-events/press-releases/press-release-details/2025/Surging-Data-Center-Growth-to-Help-Lower-Energy-Costs-for-PGE-Customers/default.aspx.

[33] Virginia State Corporation Commission. Case No. PUR-2025-00001: Dominion Energy Virginia Biennial Review of Base Rates. Virginia State Corporation Commission, 2025, https://www.scc.virginia.gov/docketsearch/#caseDocs/146025.

[34] Fisackerly, Haley. "Amazon: Good for Mississippi, Great for Entergy Customers." Magnolia Tribune, 10 July 2025, https://magnoliatribune.com/2025/07/10/aws-good-for-mississippi-great-for-entergy-customers/.

[35] Fisackerly, "Amazon: Good for Mississippi."

[36] Fisackerly, "Amazon: Good for Mississippi."

[37] June 2025: Haley Fisackerly, president and CEO of Entergy Mississippi, at Amazon Summit DC – Energy & Grid Forum

Conclusion

This report generated the following key findings:

1. **Based on E3's analysis, the Amazon data centers in the evaluated utility regions are not being subsidized by existing ratepayers; instead, they have either a neutral impact or have the potential to generate ratepayer benefits, such as downward rate pressure, through 2030.** The Amazon data centers are estimated to generate $3.4 million of surplus utility revenue per data center in 2025 and up to $6.1 million in 2030, assuming a 100 MW data center. This surplus revenue could be used to benefit ratepayers, such as providing downward rate pressure, but how this potential benefit is realized will differ across jurisdictions. The evaluated data centers are geographically diverse, representing a wide range of sites, regions, and market structures. None of the studied regions showed negative revenues (i.e., subsidies); all yielded sufficient or surplus revenues.

2. **In the long-term, rate design must keep pace with load growth to ensure these outcomes moving forward.** As demand from large loads continues to grow rapidly and dynamically, utilities must adapt rate structures as needed to ensure sufficient cost recovery, fair cost allocation and mitigate key risks. The overarching best practices, archetype framework, and menu of tools outlined in this paper and profiled in the case studies can help support utilities and regulators in continuing to prevent cross-subsidization while ensuring long-term growth and stability.

3. **Large loads can provide meaningful benefits to ratepayers and the broader electric system by driving critical investments in grid infrastructure beyond their own energy needs, enhancing reliability and spurring economic growth.** These investments can help modernize, harden, and expand the broader electricity grid, creating excess capacity that can attract additional development and economic activity. Many large loads have also committed to high levels of carbon-free generation, providing strong financial incentives to deploying renewables today and for emerging technologies critical to the long-term clean energy transition. Amazon in particular is poised to enable nearly 4.2 GW of new solar and wind, which will produce the energy equivalent to powering over 1 million homes in the case study regions.

4. **Innovative solutions can play a key role in addressing current challenges.** Larger loads, utilities, and power producers are adopting new technologies and unique contract structures to address capacity constraints and improve grid efficiency in the face of today's challenges. Key innovations include self-supplying generation, new rate structures and financing arrangements to support clean energy integration, and de-risking emerging technologies critical to the clean energy transition. Stakeholders should continue collaborating and innovating to help meet growing demand while generating broader benefits.

Appendix A. Detailed Information Related to Existing Large Load Rate Designs

The tables below detail the diverse rate structures for large loads, illustrating the tools discussed in the paper to recover costs, manage risk, and support economic development. The utilities vary widely (in terms of size, business model, region, market structure, etc.), risk vs. growth appetite, and the amount of load growth in their territory, resulting in a vast spectrum of tariff structures and combinations of tools.

A.1. Existing Rates from Large Load Tariffs

1. Existing Rates

Utility *Tariff*	Status/Year	Utility Type	Cost Allocation Practices	Rate Structure Elements	Energy Charge	Demand Charge	Inter-connection Fees	Load Flexibility	Applicability	Contract Length	Renewable Policy
APS *XHLF Rate*	Part of the 2016 rate case; has been in effect since 2018, with no changes except rate increases	IOU	Responsible for Tx costs/upgrades if load is >3MW and if APS must extend, relocate, or upgrade its facilities to provide service	High basic service charge, especially at the transmission level; can be bundled/ unbundled	$0.042/kWh; Volumetric component is $0.062 (51% of total bill) including riders	$13-14/kW (47% of total bill)	Execute a line extension agreement; can be served with Tx level service by providing APS with a CIAC (contribution in aid of construction)	XHLF tariff is not applicable to critical peak pricing or interruptible service rate riders	Must have a consistent 92% load factor	Customers required to execute an agreement that specifies contract length	Carbon free from at least 50% of energy consumption annually (can be met by RECs)
PG&E *B-20*	Active rate	IOU	Rate based on allocations for generation, distribution, transmission, and reliability services costs Customer may have to pay some of the cost for any new facilities needed to provide the customer with service	Bundled time-of-use rates with customer, demand, energy, and power factor adjustment, and peak day pricing charges Charges based on secondary, primary, or transmission voltage	Varies by season, time of day, and secondary, primary, or transmission voltage	Varies by season, time of day, and secondary, primary, or transmission voltage	Customer may have fees included as part of a line extension agreement	None	Maximum demand exceeding 999 kW for at least three consecutive months	Terms and conditions for repayment for PG&E's investments specified in line extension agreement	None

Utility *Tariff*	Status/Year	Utility Type	Cost Allocation Practices	Rate Structure Elements	Energy Charge	Demand Charge	Inter-connection Fees	Load Flexibility	Applicability	Contract Length	Renewable Policy
Mid American Energy *SS*	Active rate	IOU	Customer may be required to provide payment agreements that allow for the utility's recovery of upgrade costs	Service, energy, demand, and reactive demand charges	Tiered charges varying by season	$3/kW summer, $2.75/kW winter	May apply if transmission and substation upgrades are required	None	Demands up to 15 MW or 3 MW served directly from company-owned or customer-owned substation, respectively	None	None
Mid American Energy *ICR*	Active rate	IOU	Customer may be required to provide payment agreements that allow for the utility's recovery of upgrade costs	Service, energy, demand, and reactive demand charges	Varies based on time of day and season	Varies based on customer and demand	May apply if transmission and substation upgrades are required	None	Demands >= 15 MW or 3 MW served directly from company-owned or customer-owned substation, respectively	None	None
Rocky Mountain Power *Schedule 34*	Active rate; most recent revision in docket no. 24-035-T07	IOU	Customer charges consider use of system facilities and contributions to system fixed costs	Normal tariff rate with an incremental charge equal to the difference between the cost to supply clean generation to the customer and avoided costs	Normal tariff rate with incremental charge	Normal tariff rate with incremental charge	Non-refundable application fee of $5,000	None	Customers with a total aggregated load of at least 5 MW based on annual peak load	Obligations to pay all of the costs of the clean energy resources	Electricity must come from clean energy resources
Black Hills Energy *Large Power Contract Service*	Active rate since 2016	IOU	Transmission costs based on cost to use the utility's transmission system and costs allocated to the customer for network service	Microgrid management fee, energy charge, transmission costs, administrative costs	Based on energy procured or generated on behalf of the customer	Multiple charges for microgrid manage-ment, transmission, and adminis-tration	None	None	New load with capacity requirement of 13 MW or greater; agree to generation on-site for providing backup service	Termination provisions requiring minimum four-year notice to move to different tariff	Utility can procure competitively priced renewables for customers

Utility *Tariff*	Status/Year	Utility Type	Cost Allocation Practices	Rate Structure Elements	Energy Charge	Demand Charge	Inter-connection Fees	Load Flexibility	Applicability	Contract Length	Renewable Policy
Georgia Power *Power and light high load factor PLH-13*	2022	-	Rate based on allocations for generation, transmission, and distribution costs. Customer may have to pay some of the cost for any new facilities needed to provide the customer with service	Basic service charge: $1,195 (3% total) Demand Charge, Energy Charge, excess kVAR charges, Environmental Compliance Cost Recovery, Nuclear Construction Cost Recovery, Fuel Cost Recovery as applied to the current month actual kWh, Municipal Franchise Fee	Energy charge: $0.006267 / kWh Total volumetric: $0.052 /kWh (46% of bill)	$18.62/ kW (51% of bill)	Utility retains right to specify minimum billing demand and/or contract period to ensure revenue covers extra costs, or otherwise require cash contribution.	None	Applicable to all electric service to any industrial customer contracting for not less than 10,000 kW . Annual billing load factor of not less than 75%	5 years	None, customers can optionally purchase through other tariffs
Georgia Power *High load factor Time of use TOU-HLF-15*	2024	-	Rate based on allocations for generation, transmission, and distribution costs. Customer may have to pay some of the cost for any new facilities needed to provide the customer with service	>95% Energy charges; $221.00 Basic Service Charge plus Environmental Compliance Cost Recovery, plus Demand Side Management Commercial Schedule, plus Municipal Franchise Fee	On-Peak Rate: 17.0449¢ / kWh Off-Peak Rate: 4.9035¢ /kWh	NA	Utility retains right to specify minimum billing demand and/or contract period to ensure revenue covers extra costs, or otherwise require cash contribution.	None	Applicable to commercial customers who initially enroll 20 or more accounts on the rate. For each account, average monthly load factor of 60% or greater. Monthly peak of minimum 526 kW per account during summer.	1 year	None, customers can optionally purchase through other tariffs

Utility *Tariff*	Status/ Year	Utility Type	Cost Allocation Practices	Rate Structure Elements	Energy Charge	Demand Charge	Inter-connection Fees	Load Flexibility	Applicability	Contract Length	Renewable Policy
NV Energy *Clean Transition Tariff*	Approved 2025	IOU	Customer must pay for the utility's costs associated with procuring the energy, transmission, and distribution Capacity protection cost to equalize the rate with that of the otherwise applicable rate class	Energy pricing with fixed and variable components applicable during resource and non-resource production hours, respectively Follows the otherwise applicable rate but removes the generation capacity and energy supply costs through bill credits	Project-specific charge that accounts for the cost of the project, capacity portion of grid-served energy, planning reserve margin, and capacity protection cost	Follows the otherwise applicable rate schedule if applicable	None	None	Eligible fully-bundled retail customers with an annual average hourly load of 5 MW or more Customer may take service for all or a portion of its total load	Term length that aligns with the life of the renewable resource	Can provide access to new renewables by paying a premium but the project must be a renewable resource not previously approved by the Commission
AEP Ohio *Data Center Power Tariff*	Approved 2025	IOU	Minimum demand requirements to ensure that investments in the system will be paid for by data center customers instead of other customers	Increase in minimum demand charge from 60% to 90% to cover expected costs of future transmission needs	Same as rate paid by general service customers	No less than 90% of the customer's contract capacity	N/A	None	New data center customers with monthly max. demand of 25 MW or greater at single location. Minimum credit rating A- from S&P Global and A3 from Moody's, and cash greater than 10x collateral requirement, or guarantee of 50% of total minimum charges for full term	10 years with option to pay an "exit fee" after 5 years. Can assign up to 25% of contracted capacity to another customer when exiting	None
Pacific Power *Schedule 48 + Capacity Reservation and Excess Demand Charges*	Active rate, revised 2025	IOU	Additional measures to protect other consumers if loads do not materialize. Company may require a customer to reserve capacity and pay if under/ overutilized.	Flat energy charge with monthly on-peak demand charge, plus a Capacity Reservation Charge of $3.68/kW per kW of demand reserved.	$0.057/kWh on-peak and $0.048/ kWh off-peak	$8.92/kW on-peak. Excess demand charge of $11/kW if customer goes above their contracted Reserved Capacity.	Full line extension cost owed up front. Customer must pay Capacity Reservation Charge regardless of whether they use the full contracted amount of Reserved Capacity.	None	Customers >1MW of peak demand at least once in the preceding 18 months. Remains applicable until stays below 1MW for 36 months.	Not less than 1 year	None

2. Proposed Rates

Utility *Tariff*	Status/Year	Utility Type	Cost Allocation Practices	Rate Structure Elements	Energy Charge	Demand Charge	Interconnection Fees	Load Flexibility	Applicability	Contract Length	Renewable Policy
Duke Energy *GSA, ACE Tariffs incl. GSAC-1*	Signed MOU with large tech companies to develop these tariffs but have not been approved by Commission. Would update the Green Source Advantage program.	IOU	Will include protections for non-participating customers	Administratively established Avoided Cost Bill Credit for hourly marginal production cost OR product charge negotiated with renewable energy supplier	Pays the amount computed under the primary rate schedule + CEEA charge	Pays the amount computed under the primary rate schedule	M4 deposit is equal to 100% of the project's assigned Network Upgrades	Planned to facilitate participa -tion in load flexibility programs	Minimum take clause Customers can contract for 100% of their energy use	Term can be 2, 5, 10, 15, or 20 years	Matches customer load with clean energy generation; customer can negotiate the construction of a renewable energy project/ contract with developers
Appalachian Power Company *LPS*	Proposed additional requirements under existing tariff, focused on customers >100MW	IOU	Traditional class allocations + minimum demand requirements and exits fees to ensure that investments in the system will be paid for by data center customers instead of other customers	Flat energy charge with monthly peak demand charge, including minimum charge	$0.00386/ kWh, minimum charge equivalent to 60% load factor	$9.96/kW, 80% monthly minimum billing demand relative to contracted capacity	None, except customer must provide collateral tied to historic/ expected non-fuel costs of service	None	Customers over 150MW across multiple sites, or >100MW on individual site	Minimum 12 years, five-year notice to discontinue or modify service otherwise exit fee is assessed	None

3. Northern Virginia Rates

Utility *Tariff*	Status/ Year	Utility Type	Cost Allocation Practices	Rate Structure Elements	Energy Charge	Demand Charge	Interconnection Fees	Load Flexibility	Applicability	Contract Length	Renewable Policy
NOVEC *HV-1*	Active rate	Coop	Customer must pay one-time contribution to cover the total cost of any investment in primary distribution facilities Capacity and transmission costs covering the customer's load ratio share of NOVEC's capacity obligation to PJM and transmission costs	Capacity costs, transmission costs, energy charge, service charge, and distribution charges (applicable to both energy and demand) Service charge $1,050/month	$0.07590/ kWh energy charge $0.00212/ kWh distribution charge	$1.31/kW distribution charge	Excess facilities charges may apply for substation, primary distribution, and high voltage line investments in excess of those normally provided for the same type of service	None	Served from facilities 115 kV or greater at delivery voltage of 12.5 kV or greater, new or separate load of at least 5 MW, maintain average load factor of 70%	Negotiable but structured to recover the full cost of distribution and/or subtrans -mission plant investment and O&M	None
NOVEC *HV-2*	Active rate	Coop	Customer must contract for demand and an annual load factor sufficient to protect the financial investment made by NOVEC	Distribution charges including service, demand, rKVA, and energy charges Service charge $1,420/month rKVA charge: $0.16/rKVA	$0.000337/ kWh distribution charge, market-based energy charge	$0.793/kW distribution charge	Excess facilities charges may apply for substation, primary distribution, and high voltage line investments in excess of those normally provided for the same type of service	None	Agree to minimum contract billing demand of 65 MW or be served at delivery voltage of 34.5 kV or greater and agree to contract billing demand of 45 MW or more; maintain average load factor of 85%	Negotiable but structured to recover the full cost of distribution and/or sub-transmission plant investment and O&M	None
Dominion *GS-3*	Active rate	IOU	Rate based on allocations for distribution and generation costs	Distribution service charges and electricity supply service charges with on-peak and off-peak components Subject to all applicable riders $0.175/rKVA distribution charge	¢0.0084/kWh distribution charge $0.3876/ kWh on-peak and $0.2609/ kWh off-peak generation charges	Distribution, on-peak generation, off-peak generation, and transmission charges	Minimum demand charge of 70% of the transformer size built to serve the customer, plus additional revenue guarantee may be required for distribution upgrades >$350k	None	Secondary voltage customer with peak demand of at least 500 kW during at least three billing months	Open order	None; customers can voluntarily purchase renewable attributes through Schedule RF

Utility *Tariff*	Status/ Year	Utility Type	Cost Allocation Practices	Rate Structure Elements	Energy Charge	Demand Charge	Interconnection Fees	Load Flexibility	Applicability	Contract Length	Renewable Policy
Dominion *GS-4*	Active rate	IOU	Rate based on allocations for distribution and generation costs	Distribution service charges and electricity supply service charges with on-peak and off-peak components Subject to all applicable riders $0.203/rKVA distribution charge	¢0.0091/kWh distribution charge $0.3876/ kWh on-peak and $0.2609/ kWh off-peak generation charges	Distribution, on-peak generation, off-peak generation, and transmission charges	Minimum billing demand of 70% of the transformer size built to serve the customer, plus additional revenue guarantee may be required for distribution upgrades >$350k	None	Non-residential transmission or primary voltage customer with peak demand of at least 500 kW during at least three billing months	Open order	None; customers can voluntarily purchase renewable attributes through Schedule RF
Dominion *MBR*	Active rate (experi -mental)	IOU	Rate based primarily on direct wholesale costs of serving the customer, pls formula allocation of distribution costs	Dynamic energy and demand charges based on wholesale prices, plus flat distribution charge. Subject to applicable riders	Tied to day-ahead energy market prices, plus a margin of at least $0.00085/ kWh depending on customer load factor	Tied to PJM capacity market prices, plus transmission demand charge as applicable to other customers	Minimum billing demand of 70% of the transformer size built to serve the customer, plus additional revenue guarantee may be required for distribution upgrades >$350k	None	Non-residential transmission or primary voltage customer with peak demand of at least 5.000 kW in the past year	Three-year term, automatically renews	None; customers can voluntarily purchase renewable attributes through Schedule RF
Rappahan -nock Electric Cooperative *LP-DF*	Proposed 2025	Coop	Requires upfront contribution-in-aid-of-construction, collateral, and contribution margin; costs of service fully assigned to customers	Service and delivery charges based on installed substation infrastructure, third-party PSA	Customer executes PSA, is also responsible for all capacity and transmission charges incurred by the co-op related to serving customer	Based on installed MVA of delivery infrastructure, $874/MVA; Plus monthly service charge $529/MVA/ substation built to serve the customer	Excess facilities charge applicable on case-by-case basis, customer shall pay contribution-in-aid-of-construction and monthly fixed charge to recover	None	Must be served by dedicated substation, contracted billing demand >25MW, average annual load factor >75%	Negotiable but structured to recover the full cost of distribution and/or sub-transmission plant investment and O&M	None