ANALYSIS GROUP

Co-Located Load

Market, Economic, and Ratemaking Implications

Authors:

Todd Schatzki

Joseph Cavicchi

Megan Accordino

October 28, 2024

Acknowledgments

This is an independent study prepared by the authors at the request of Talen Energy Corporation. The authors appreciate the support of Talen Energy Corporation, and the research and analytic support of their Analysis Group colleagues Rachel Anderson, Scott Ario, Alison Li, Eshika Arora, Sanjam Chhabra, Emily Langton, Tag Curwen, and Josh Kirschner. The report, however, reflects the analysis and judgment of the authors alone.

About the Authors

Todd Schatzki, a Principal at Analysis Group, is an economist with expertise in energy and environmental economics, policy, and regulation. He has extensive experience in the operation and regulation of markets for wholesale and retail electricity markets, natural gas, and other fuels. In wholesale electricity markets, his work includes review and redesign of market rules used in organized wholesale markets, economic analyses of the impacts of proposed market rules and infrastructure changes, evaluation of the rules and procedures for market monitoring and mitigation in organized markets, evaluation of the conduct of market participants with respect to allegations of market manipulation, and assessment of economic damages associated with wholesale power contracts disputes. He has worked directly with independent system operators including ISO New England Inc. and New York Independent System Operator, Inc., and been engaged on other work involving organized and non-organized wholesale markets including those administered by Alberta Electric System Operator, Midcontinent Independent System Operator, PJM Interconnection, L.L.C., and Southwest Power Pool, Inc., as well as in Western U.S. wholesale electricity markets. He has testified before the Federal Energy Regulatory Commission and state and Canadian provincial regulatory commissions, and submitted testimony in federal courts and before arbitrators. Across engagements, he has worked on behalf of system and market operators, market monitors, regulators, generation, transmission and utility companies and other market participants.

Joseph Cavicchi, a Vice President at Analysis Group, is a power system economist that provides economic analysis, reports and testimony in various forums including state and federal regulatory proceedings related to electricity markets. Throughout his career, he has been directly involved with corporations, private and public institutions, and state and federal regulatory authorities in connection with the economics of the electricity industry. For the past 27 years, he has been working almost exclusively on issues related to the electricity industry. In addition, during the first decade of his career, he worked as a mechanical engineer and project manager at a complex that simultaneously produced (cogenerated) steam and electricity to support building operations. He has overseen the design, engineering, construction, and start-up of a cogeneration plant that provides electricity and steam to power, heat, and cool numerous buildings at a large university complex. He is also a registered professional engineer (mechanical) in the State of Massachusetts.

Megan Accordino, Ph.D., a Vice President at Analysis Group, is an economist specializing in advising clients in energy and finance-related litigation and regulatory matters. Her expertise spans competition-related matters, ratemaking cases, litigation, and policy research. In particular, Dr. Accordino has analyzed market power in mergers and market-based rate authority applications in the electric industry and analyzed allegations of market manipulation in electricity, natural gas, and other commodity markets. Her ratemaking experience includes developing cost-of-service studies, analyzing investment and operational decisions under regulatory principles, and analyzing utility rate plans in light of market conditions and their impacts on stakeholders. Dr. Accordino has also analyzed liability, loss causation, and damages in numerous litigation matters. Dr. Accordino has authored articles on offshore wind procurement practices, the impact of overlapping greenhouse gas emissions policies (published in *The Energy Journal*), and market definition in electric power markets (published in the *ABA Economics Committee Newsletter* and *The Electricity Journal*).

About Analysis Group

Analysis Group is one of the largest economics consulting firms, with over 1,200 professionals across 14 offices in North America, Europe, and Asia. Since 1981, Analysis Group has provided expertise in economics, finance, analytics, strategy, and policy analysis to top law firms, Fortune Global 500 companies, government agencies, and other clients. The firm's energy and climate practice area is distinguished by its expertise in economics, finance, market modeling and analysis, economic and environmental regulation, analysis and policy, and infrastructure development. Analysis Group's consultants have worked for a wide variety of clients, including energy suppliers, energy consumers, utilities, regulatory commissions, other federal and state agencies, tribal governments, power system operators, foundations, financial institutions, start-up companies, and others.

Table of Contents

I. Executive Summary

After decades of flat to declining growth in loads, the electric power industry is now experiencing a resurgence in demand for service. This resurgence is coming from many sources. Growing interest across states in decarbonization of energy use has prompted policies and technology changes aimed at the electrification of transportation and heating, activities traditionally powered through fossil fuels, with growth anticipated over the coming decades. The past several years have also seen a sudden surge in demand from the digital economy, particularly from data centers and to a lesser degree cryptocurrency mining. As this surge has occurred, data centers (and cryptocurrency miners) have been experimenting with various contractual approaches and physical structures to acquire electric energy service.

One approach is co-location of loads and generation. In co-location arrangements, loads locate at the site of new or existing generation facilities behind the same meter. To meet corporate commitments to decarbonization goals, technology companies often propose co-location arrangements with nuclear or renewable generation, potentially co-located with battery energy storage as well. Co-location with existing generation plants has drawn particular attention, with articles, white papers, and regulatory interventions raising a number of issues, including the impact of co-location on market outcomes and reliability, whether co-located loads are taking service from the networked grid, and whether co-located loads are bearing a fair portion of the networked grid's costs.[1] These issues are playing out in at least two regulatory proceedings: (1) in the proceeding to amend the Interconnection Service Agreement ("ISA") for the Susquehanna nuclear plant to increase the permitted quantity of co-located load,[2] and (2) in a proceeding initiated by Exelon aimed at requiring all synchronized co-located loads to take network transmission service (on a gross load basis).[3] The heightened interest in co-location has drawn regulatory attention.[4] We evaluate these issues, as well as ratemaking concerns associated with co-located loads, and reach a number of conclusions.

First, the consequences for load growth on energy and capacity markets are generally the same whether load co-locates behind-the-meter or connects directly to the transmission system of a regional transmission organization

---

[1] *See,* Hartman, D. and K. Chandler, "The Fuss and Advantages of Siting Large Consumers at Power Plants," R Street, September 16, 2024, available at https://www.rstreet.org/commentary/the-fuss-and-advantages-of-siting-large-consumers-at-power-plants/. *See also,* Clark, T. and V. Duane, "What Happens When a Nuclear Plant and a Data Center Shack Up?", Wilkinson Barker Knauer, April 2024, available at https://www.wbklaw.com/wp-content/uploads/2024/04/What-Happens-When-a-Nuclear-Plant-and-a-Data-Center-Shack-Up-White-Paper-4.18.24.pdf, ("Duane and Clark I"); Duane, V. and T. Clark, "The Co-Lo Conundrum, Protecting Customers in Nuclear-Data Center Colocation," Wilkinson Barker Knauer, September 23, 2024, available at https://www.wbklaw.com/news/white-paper-the-co-lo-conundrum/, ("Duane and Clark II"); Kormos, M., "The Co-Located Load Solution", Nuclear Energy Institute ("NEI"), July 2024, available at https://www.nei.org/www.nei.org/files/26/2679b7cf-cb96-4aaf-b360-a0af3ec0a381.pdf; Declaration of John J. Reed and Danielle S. Powers in Support of Protest of Exelon Corporation and American Electric Power Services Corporation, FERC Docket No. ER24-2172, June 24, 2024, ("Reed and Powers Declaration").

[2] PJM Interconnection, L.L.C., Amendment to ISA, SA No. 1442; Queue No. NQ-123, Docket No. ER24-2172, June 1, 2024, ("Susquehanna ISA"). Two of this white paper's authors filed a declaration addressing issues raised in certain protests, answers, and declarations filed in response to the amended ISA. *See* Declaration of Todd Schatzki and Joe Cavicchi, PJM Interconnection, LLC, Docket No. ER24-2172-001, September 24, 2024.

[3] Protest of Exelon Corporation and American Electric Power Service Corporation, FERC Docket No. ER24-2172, June 24, 2024, ("Exelon/AEP Protest").

[4] *For example*, FERC assembled a technical conference on co-located loads. Commissioner-led Technical Conference on Co-location of Large Loads at Generating Facilities, Docket No. AD24-11-000, November 1, 2024.

("RTO") or independent system operator ("ISO"). In either case, load growth increases the demand for energy and capacity and can be expected to put upward pressure on wholesale market prices – all else being equal. However, holding quantity and location fixed, the configuration of the load – whether co-located or on the system – would not be expected to affect energy market outcomes as it does not affect the aggregate supply-demand balance. Within the capacity market, expected price increases would be smaller with fully-isolated behind-the-meter co-located load, as the market impacts would not reflect the additional reserve margin required when load is located directly on the network.

Second, while the cost impact of any specific co-located load will depend on existing power flows and the existing grid, in principle, co-locating load at existing generation plants would reduce the distance between generation and loads, which is consistent with a more efficient grid, as well as a reduction in capital costs, energy losses, and operating and fuel costs. Limiting co-location of loads would raise costs, which could be substantial, to accommodate the tremendous pace of data center (and other) load growth, which would require billions of dollars of new investment.

Third, ratemaking for co-located loads will depend on the loads' use of network transmission service and ancillary services. Under existing Federal Energy Regulatory Commission ("FERC") ratemaking, consistent with cost causation principles, fully-isolated co-located loads are not utilizing network transmission service. Network transmission service provides the delivery of energy (and capacity) from network generators to network loads, which is not the arrangement with fully-isolated co-located loads, as they are designed not to withdraw energy from the network. Further, behind-the-meter ratemaking reflects netting of generation and loads, such that loads are only charged for actual withdrawals from the network. This approach to ratemaking is common in RTO/ISO systems and consistent with cost causation and economically efficient rates, as such loads do not impose any incremental costs on the network. Recent estimates of "cost shifts" due to fully-isolated co-located loads ignore these ratemaking principles, in effect assuming that all co-located loads are required to take monopoly distribution service.

In summary, there is nothing unique about the co-location of digital loads with generation that distinguishes the circumstances of co-location from those that have been addressed previously by FERC. While concerns have been raised that the scale of co-location of digital loads will have "huge" and "profound" effects,[5] the implications of these concerns is that somehow FERC has been approving unjust and unreasonable rates for more than 20 years but that it just did not matter because the scale of the co-location was small. This is illogical and ignores that the rationale used to determine whether rates are just and reasonable reflects ratemaking principles, such as efficiency and fairness, that do not depend on scale.

II. Broader Context for Co-Location

After decades of flat or declining growth in load, the electricity sector is now facing substantial growth in demand. Utilities and grid operators have been planning for growth driven by the electrification of transportation and heating to achieve policy objectives, but these efforts have been overtaken by the sudden and unexpected growth in

[5] Exelon/AEP Protest, at p. 2.

demand from new large-scale users, such as data centers and cryptocurrency mining. At the same time, demand from customers and policymakers to reduce electricity sector emissions is ushering in a transition from fossil-fueled to zero-carbon generation technologies. This transition is creating substantial demand for new zero-carbon resources, not only to replace retiring fossil-fueled generation but also to meet the growth in demand, and is presenting new challenges in maintaining system reliability due to the intermittent nature of solar, wind and other zero-carbon resources.

As load requests have grown rapidly and unexpectedly, many utilities have found that substantial distribution and transmission system upgrades are needed to meet the increasing customer demands. This has led to long wait times for load interconnection requests across the U.S., as utilities assess the impacts of adding such large new loads to the system. As a result, some large customers are exploring "co-located load" arrangements, where the load is physically connected to an on-site generation unit that provides electricity without using the distribution or transmission network. While some co-located loads, like cogeneration facilities or load with distributed energy resources ("DER") like solar or energy storage, may rely on the grid for some part of their electric supply, others are designed to operate independently without drawing any power from the grid—we refer to these loads as "fully-isolated co-located loads." Although such facilities may account for only a modest portion of total load growth from new large load customers and do not themselves use the distribution or transmission network, there is growing concern about their potential adverse effects on those who do use the network.

A. Historical Demand Trends and Surge from AI Boom

The last 50 years has seen a steady decline in load growth. As shown in **Figure 1** and **Figure 2**, from 1970 to 2010 total U.S. electricity demand growth declined from nearly 5% to 2%, while averaging 3% annually over the period. Yet, load growth continued as technological innovations spread, air conditioning became more widely adopted, and industries with high electricity needs continued to expand. Between 2010 and 2023, demand growth slowed to an average of 0.2% per year, primarily due to increased energy efficiency measures and changes in the structure of the U.S. economy (including less demand from heavy industry).[6] As demand grew, so did utility-scale generation capacity – from approximately 750 GW in 1990 to nearly 1,000 GW in 2000 to 1,200 GW in 2023, as shown in **Figure 3.**

[6] Bouckaert, S. and T. Goodson, "The mysterious case of disappearing electricity demand," International Energy Agency ("IEA"), February 14, 2019, available at https://www.iea.org/commentaries/the-mysterious-case-of-disappearing-electricity-demand.

Figure 1: U.S. Electricity Demand by End-Use Customer Sector[7]

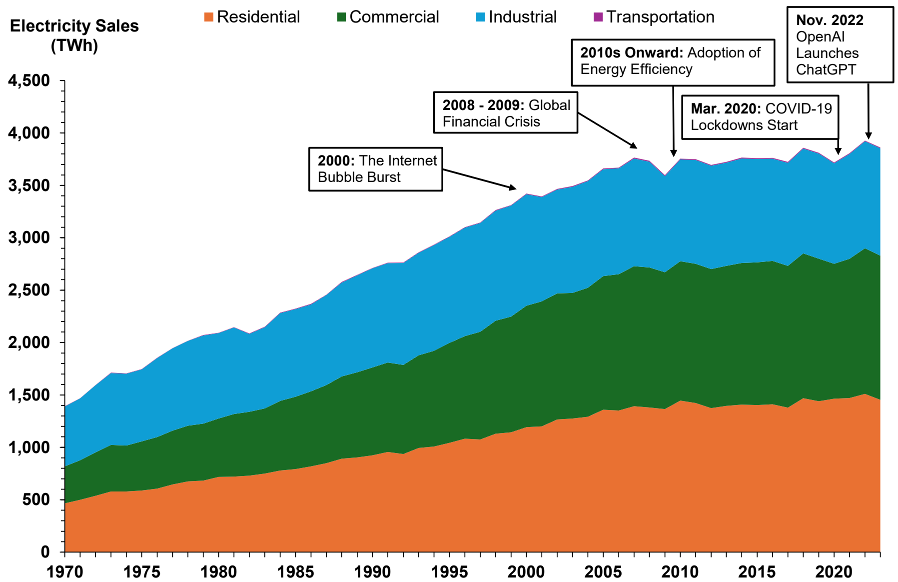
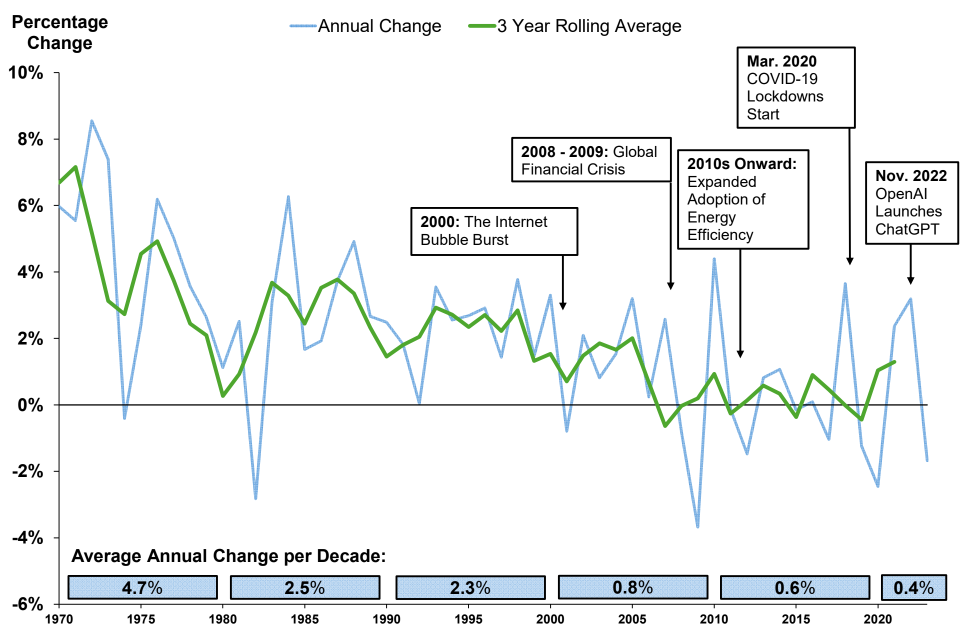


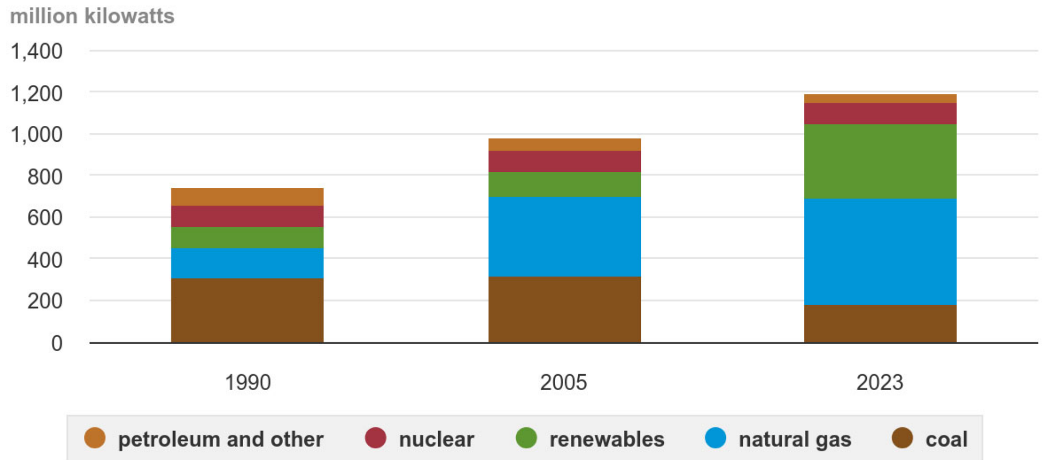
Figure 2: Annual Changes in U.S. Electricity Demand[8]



[7] "Annual Retail Sales of Electricity by Sector," Form EIA-861, U.S. Energy Information Administration ("EIA"), available at https://www.eia.gov/electricity/data/browser/#/topic/5?agg=0,1.

[8] "Annual Retail Sales of Electricity by Sector," Form EIA-861, EIA, available at https://www.eia.gov/electricity/data/browser/#/topic/5?agg=0,1.

Figure 3: U.S. Utility-Scale Generation Capacity by Major Energy Source[9]



In recent years, electricity demand has been projected to grow more rapidly, with forecasts ranging from 0.6% per year to 3.4% per year, as shown in **Figure 4** below. This increase in demand is attributable to both growth in demand from data centers and the electrification of transportation and heating.[10] Where demand growth from electrification and heating has been predicted for several years, the growth in data center demand is recent and unexpected. Given how rapidly advances in artificial intelligence ("AI") are being made – the source of the surge in demand for energy from data centers – the forecasts from 2022 and 2023 shown in **Figure 4** may underpredict the growth in load going forward.[11]

Moreover, aggregate growth rates mask significant geographic variation in load growth. For example, some regions, like Texas and Virginia, have experienced annual growth rates on the order of 10-15% over the past three years[12] and are expected to continue growing rapidly.[13] Thus, the issues raised by data center growth are often most focused in particular regions.

[9] "Electricity explained: Electricity generation, capacity, and sales in the United States," EIA, July 16, 2024, available at https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php.

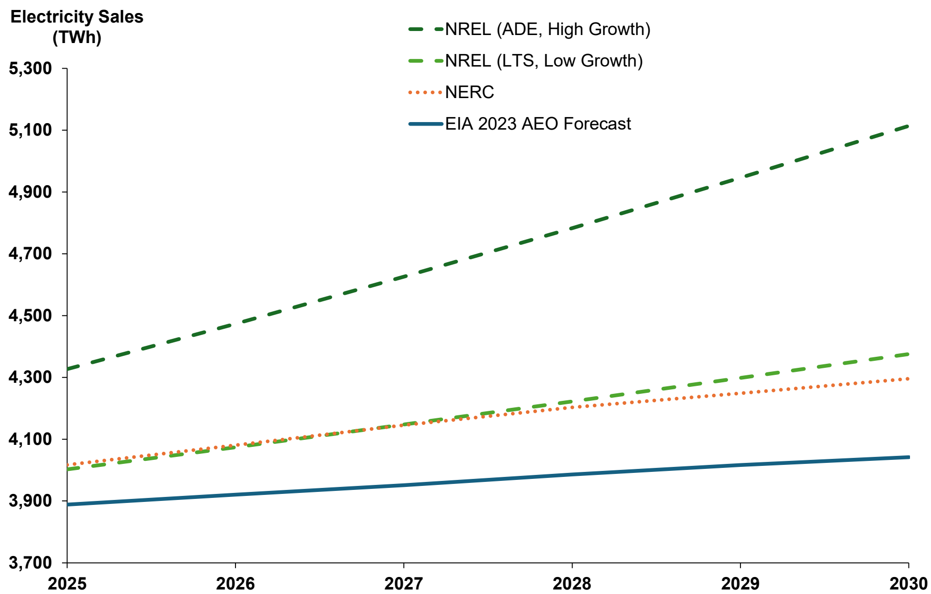
[10] "Clean Energy Resources to Meet Data Center Electricity Demand," U.S. Department of Energy ("DOE"), August 12, 2024, available at https://www.energy.gov/policy/articles/clean-energy-resources-meet-data-center-electricity-demand.

[11] For example, North American Electric Reliability Corporation ("NERC") noted that "data centers are another load compounding impact being studied." *See* "2023 Long-Term Reliability Assessment," NERC, December 2023 available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf, at p. 125.

[12] Retail sales of electricity in Texas and Virginia increased from 427 GWh to 493 GWh and 117 GWh to 132 GWh between 2020 and 2023, respectively. *See* "Annual Retail Sales of Electricity by Sector," Form EIA-861, available at https://www.eia.gov/electricity/data/browser/#/topic/5?agg=0,1.

[13] For example, Dominion Energy forecasts demand for electricity in Virginia to grow around 5% annually for the next decade. *See Commonwealth of Virginia, ex rel. State Corporation Commission, In re: Virginia Electric and Power Company's 2024 Integrated Resource Plan*, Case No. PUR-2024-00184, October 15, 2024, available at https://www.dominionenergy.com/-/media/pdfs/global/company/IRP/2024-IRP-w_o-Appendices.pdf, at p. 8.

Figure 4: Comparison of U.S. Electricity Demand Forecasts[14]



Rapid growth in data center load results from innovation in the digital economy, including advances in and the growing commercialization of AI.[15] Given its potential to transform major aspects of work and day-to-day life, AI is widely understood to be of critical strategic importance to both the US economy and national security.[16] Unlocking the potential of AI and maintaining global competitiveness in the field requires adequate infrastructure and energy supply to train, use, and adapt AI models, particularly large language models ("LLMs"), some of which require about 10 times more energy for a single query than a typical Google search.[17] Moreover, approximately 30% of the overall energy footprint of AI at this time is attributable to model training, which requires processing a vast

[14] NREL uses different assumptions about electrification growth rates compared to the EIA, which bases its demand projections on historical load shape data. NREL's ADE case assumes extensive electrification alongside decarbonization measures, while the LTS scenario reflects greater energy efficiency adoption with less electrification. NERC's forecast aggregates projections provided by each assessment area across the U.S. *See* 2025 - Onwards Projections by Class: "Table 2, Energy Consumption by Sector and Source," 2023 Annual Outlook, EIA, available at https://www.eia.gov/outlooks/aeo/data/browser/#/?id=2-AEO2023&cases=ref2023&sourcekey=0; "Electricity Supply and Demand Data," NERC, December 2023, available at https://www.nerc.com/pa/RAPA/ESD/pages/default.aspx; Denholm, P. et al., "Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035," National Renewable Energy Laboratory ("NREL"), 2022, available at https://www.nrel.gov/docs/fy22osti/81644.pdf.

[15] Bloomberg estimates the generative AI market will grow from $40 billion in 2022 to $1.3 trillion by 2032. *See* "Generative AI to Become a $1.3 Trillion Market by 2032, Research Finds," *Bloomberg*, June 1, 2023, available at https://www.bloomberg.com/company/press/generative-ai-to-become-a-1-3-trillion-market-by-2032-research-finds/.

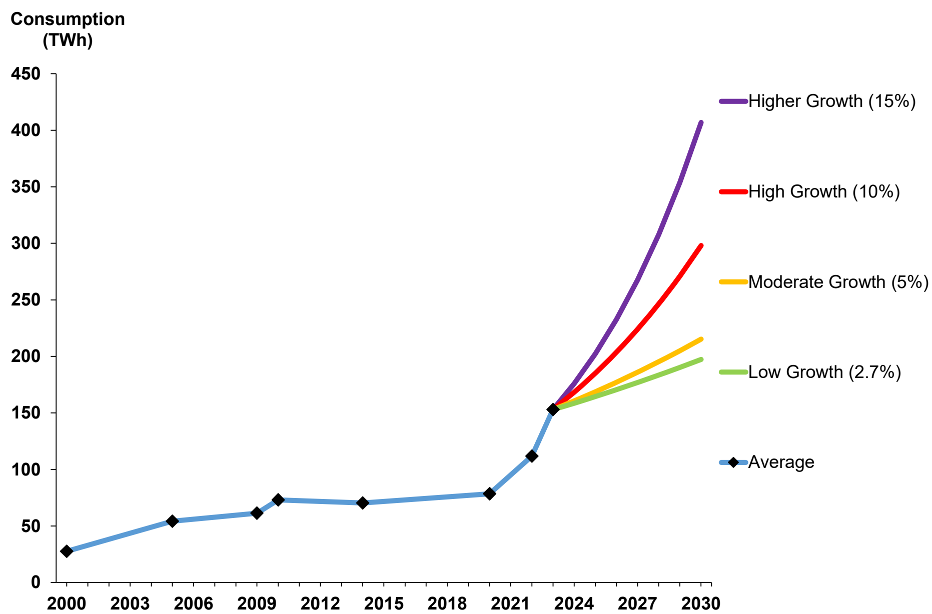
[16] "Artificial Intelligence-Artificial Intelligence and Foreign Policy," U.S. Department of State, available at https://www.state.gov/artificial-intelligence/#:~:text=Artificial%20Intelligence%20and%20Foreign%20Policy&text=Together%20with%20our%20allies%20and,security%2C%20and%20promote%20our%20values.

[17] The International Energy Agency ("IEA") estimated a single ChatGPT query requires 2.9 watt-hours of electricity compared with 0.3 watt-hours for a Google search. *See* "Electricity 2024, Analysis and Forecast to 2026," IEA, Revised January 2024, available at https://iea.blob.core.windows.net/assets/6b2fd954-2017-408e-bf08-952fdd62118a/Electricity2024-Analysisandforecastto2026.pdf, at p. 34.

array of data to improve predictions and decisions.[18] LLMs will continue to drive up demand as they improve and become more widespread across different use cases. In addition, other trends and innovation in the digital economy, such as cryptocurrency mining, are increasing electricity demand. The U.S. Energy Information Administration ("EIA") estimates that electricity used for cryptocurrency mining represents between 0.6% and 2.3% of total U.S. electricity consumption.[19]

Innovations in the digital economy have led to a rapid and unexpected increase in electricity demand that could accelerate further. As **Figure 5** illustrates, data center electricity demand hovered around 80 TWh per year between 2010 and 2020 before rising precipitously (nearly doubling) to approximately 150 TWh in 2023. Forecasts suggest continued growth. For example, the Electric Power Research Institute ("EPRI") estimates that data center electricity demand could grow by as much as 15% per year to more than 400 TWh by 2030.[20]

Figure 5: U.S. Data Center Historical and Projected Electricity Consumption[21]



[18] "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption," Electric Power Research Institute ("EPRI"), May 28, 2024, available at https://www.epri.com/research/products/3002028905, at p. 15.

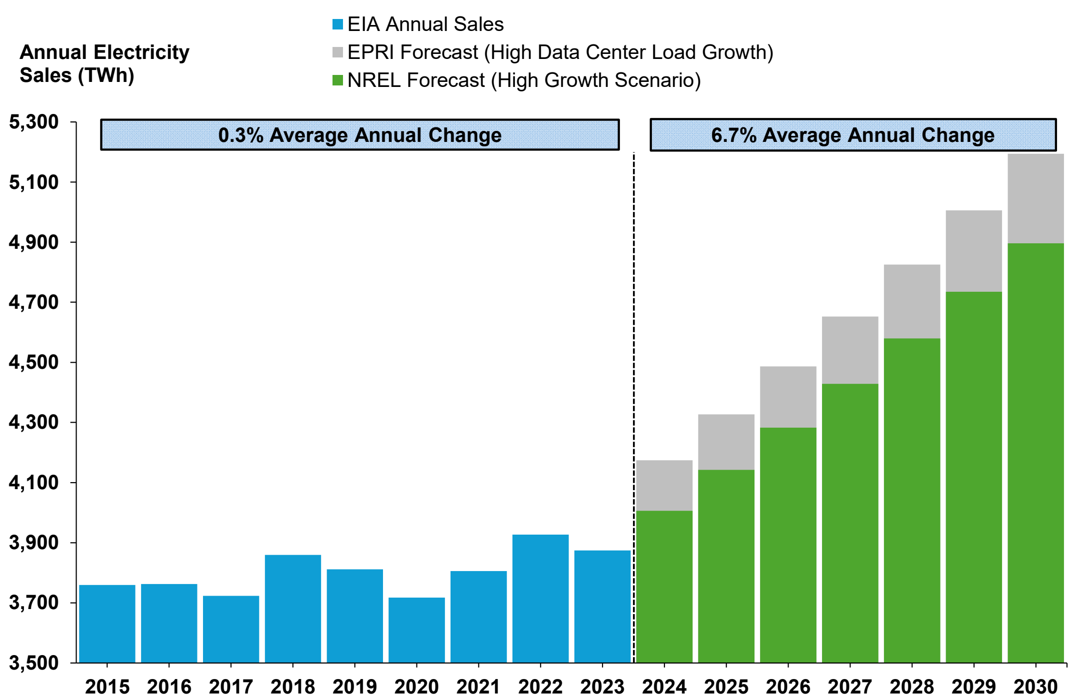
[19] Walton, R., "EIA prepares for second attempt to survey bitcoin miners about electricity consumption," Utility Dive, July 11, 2024, available at https://www.utilitydive.com/news/federal-government-prepares-second-attempt-to-survey-bitcoin-miners-energy-se/721063/.

[20] EPRI estimates four compound annual growth rates using multiple expert sources surveyed in November 2023. Their analysis reflects "historical trends for the AI industry, internet traffic, demand for storage, coupled with the computational intensity and prevalence of AI models." *See* "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption," EPRI, May 28, 2024, available at https://www.epri.com/research/products/3002028905, at p. 17.

[21] *See* "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption," Figure 11, EPRI, May 28, 2024, available at https://www.epri.com/research/products/3002028905, at p. 17.

In addition to data center load growth, the electrification of transportation and heating to meet decarbonization policy objectives represents another significant source of current and future electricity demand. Federal and state policy initiatives, including the Inflation Reduction Act and state-level net-zero commitments, are focused on transforming the transportation sector from relying on internal combustion engine vehicles to electric vehicles ("EVs"), and the heating sector from relying on gas and oil furnaces to electric heat pumps.[22] For example, electricity demand from transportation electrification could grow to approximately 100 TWh by 2030.[23] **Figure 6** provides an estimate of the potential growth in demand from both data centers and from electrification by combining EPRI's 10% per year data center load growth scenario from **Figure 5** with the National Renewable Energy Laboratory's ("NREL's") "Accelerated Demand Electrification" forecast from **Figure 4,** which reflects a scenario where the majority of demand growth is expected to come from electrification. As shown in the figure, growth in data center load and electrification together could result in U.S. electricity demand growing as much as 6.7% per year over the next seven years.

Figure 6: Forecasted U.S. Electricity Demand with High Electrification and Data Center Load Growth



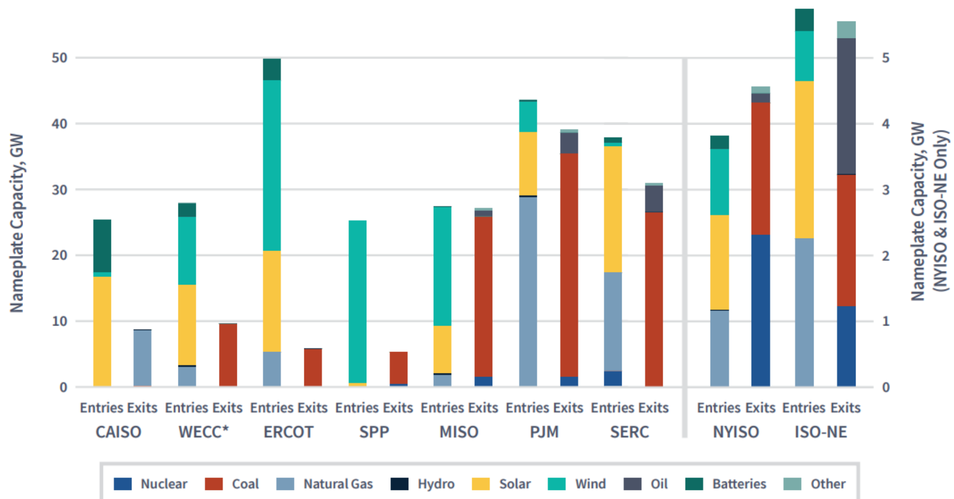
[22] Significant federal and state funding is being allocated to incentives for electrification of transportation and heating. *See* "Electricity Laws and Incentives in Federal," Alternative Fuels Data Center, DOE, available at https://afdc.energy.gov/fuels/laws/ELEC?state=US; "Federal Tax Credits for Energy Efficiency," Energy Star, available at https://www.energystar.gov/about/federal-tax-credits.

[23] "Data Centers and EV Expansion Create Around 300 TWh increase in US Electricity Demand by 2030," Rystad Energy, June 24, 2024, available at https://www.rystadenergy.com/news/data-and-ev-create-300-twh-increase-us, at p. 2.

B. Changing Electricity Supply Requirements and Arrangements

The unexpected rise in digital economy electricity demand, along with anticipated growth from electrification, is challenging an industry already in the midst of a transition in the technologies used for supplying electricity. In particular, generation capacity is increasingly constrained across the country due to retirements and impending retirements of legacy fossil fuel units, which are struggling to compete with lower-emitting and lower-cost renewables and more efficient, modern natural gas plants.[24] **Figure 7** shows that capacity additions over the past 10 years have primarily been natural gas, wind, and solar units, while most retirements have been coal and nuclear facilities.[25] Renewable energy sources like wind and solar contribute less to resource adequacy, however, because they rely on weather conditions to produce electricity. Moreover, existing fossil resource performance is being reassessed given potential constraints to fuel availability during winter periods and other factors.[26] The combination of these factors is leading to forecasted gaps in resource adequacy and reliability concerns.[27]

Figure 7: Nameplate Capacity Net Additions and Retirements by Resource Type from 2013-2023[28]



[24] "Coal and Natural Gas Plants Will Account for 98% of U.S. Capacity Retirements in 2023," EIA, February 7, 2023, available at https://www.eia.gov/todayinenergy/detail.php?id=55439.

[25] "2023 State of the Markets Staff Report", FERC, March 21, 2024, available at https://www.ferc.gov/sites/default/files/2024-03/24_State-of-the-market_0320_1715.pdf, at p. 4.

[26] For example, "ISO-NE is proposing Capacity Auction Reforms (CAR) that would transition the capacity market from a forward/annual market to a prompt/seasonal market with accreditation reforms." *See* "Capacity Auction Reforms Key Project," ISO-New England, available at https://www.iso-ne.com/committees/key-projects/capacity-auction-reforms-key-project.

Similarly, PJM is implementing adjustments to better align capacity valuation with marginal reliability contributions. *See* "PJM Response to Independent Market Monitor on 2025/2026 Base Residual Auction," PJM Interconnection ("PJM"), October 11, 2024, available at https://pjm.com/-/media/library/reports-notices/reliability-pricing-model/20241011-response-to-imm-25-26-bra-report.ashx.

[27] NERC notes "the addition of variable resources… and the retirement of conventional generation are fundamentally changing how the BPS [bulk power system] is planned and operated… [and] there is a growing risk that supplies can fall short of demand during some periods". *See* "2023 Long-Term Reliability Assessment," NERC, December 2023, available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf, at p. 31.

[28] "2023 State of the Markets Staff Report", FERC, March 21, 2024, available at https://www.ferc.gov/sites/default/files/2024-03/24_State-of-the-market_0320_1715.pdf, at p. 4.

C. Data Center Location Preferences

Data centers are characterized by unique features that influence their electricity needs and where they choose to locate. In particular, data centers are growing in scale, with recent proposals for new facilities that consume up to 100 MW, known as hyperscale data centers.[29] Once in service, electricity represents the primary input to data center operations.[30] The load profile of data centers (i.e., pattern of electricity demand over the course of a day) is currently relatively uniform,[31] but hourly variation is likely to increase as AI training needs decrease and queries from consumers increase.[32] Thus, electricity is a key input to data center operations, making geographic location an important consideration given regional differences in the price and availability of electricity. However, there are many other factors that also affect data center location, including fiber connectivity, local weather conditions (to mitigate air conditioning loads and costs), competitive retail supply options, stable power quality (to ensure reliable voltages), water access, and local financial support (e.g., tax breaks), among other factors.[33]

Data centers are being built across the U.S. One forecast, for example, anticipates more than 60% of data centers to be in the Midcontinent ISO ("MISO"), California ISO ("CAISO"), PJM, and Southeast in 2027, as shown in **Figure 8** below. Virginia, in particular, has 245 data centers covering 25 million square feet and consuming 3.6 GW of power.[34] Northern Virginia is often referred to as "Data Center Alley," as it handles more than a third of the world's online traffic with its highly-developed fiber infrastructure, reasonable energy costs, and strong tax incentives.[35] In places like Central Ohio, industrial manufacturing companies, such as aluminum smelters, were

[29] In addition, demand for data center solutions is driving the development of exascale data centers, potentially housing 100 MW to 500 MW in stand-alone facilities and in clustered campuses located strategically around the world. *See* Marangella, P., "The Gigawatt Era: From Hyperscale to Exascale," Forbes, February 29, 2024, available at https://www.forbes.com/councils/forbestechcouncil/2024/02/29/the-gigawatt-era-from-hyperscale-to-exascale/.

[30] "How Data Centers and the Energy Sector Can Sate AI's Hunger for Power," McKinsey & Company, September 17, 2024, available at https://www.mckinsey.com/industries/private-capital/our-insights/how-data-centers-and-the-energy-sector-can-sate-ais-hunger-for-power.

[31] There are components of data center electricity demand that follow standard daily use patterns and may contribute to increasing peak demand. For example, traditional data centers are estimated to use 50% of their energy consumption on extensive cooling systems to cool their equipment, with needs varying as temperature and weather varies. *See* "Data Centers and the Power System: A Primer," New England States Committee on Electricity ("NESCOE"), Spring 2024, available at https://nescoe.com/wp-content/uploads/2024/06/Data-Centers-Primer-Spring-2024.pdf ("NESCOE Data Center Report"), at p. 13.

[32] "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, available at https://www.ethree.com/wp-content/uploads/2024/07/E3-White-Paper-2024-Load-Growth-Is-Here-to-Stay-but-Are-Data-Centers.pdf, at p. 14.

[33] *See* Croteau,T., "Data Center Sites: What's Your Connection?" Q2 2023, available at https://www.areadevelopment.com/data-centers/q2-2023/data-center-sites-whats-your-connection.shtml#:~:text=Fiber%20Connectivity-,Data%20centers%20require%20ultra%2Dfast%20and%20reliable%20connectivity%2C%20so%20a,users%20as%20well%20as%20infrastructure. *See also* Olinger, E., "5 Considerations for Choosing Data Center Locations," August 6, 2024, available at https://blog.equinix.com/blog/2024/08/06/5-considerations-for-choosing-data-center-locations/.

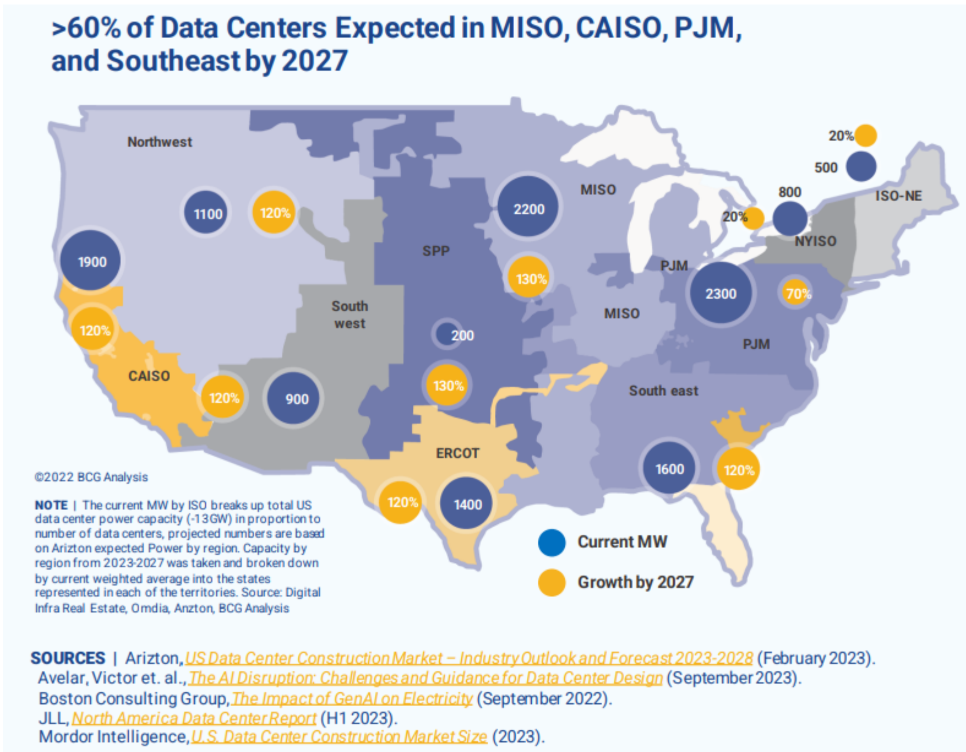
States, including Illinois and Virginia, provide tax incentives to data centers that meet the eligibility requirements related to investment amount and persons employed. *See, e.g.,* "Data Center Investment Tax Exemptions and Credits," Illinois Department of Commerce & Economic Opportunity, available at https://dceo.illinois.gov/expandrelocate/incentives/datacenters.html; "Data Center Retail Sales & Use Tax Exemption," Virginia Economic Development Partnership, available at https://www.vedp.org/incentive/data-center-retail-sales-use-tax-exemption.

[34] NESCOE Data Center Report, at p. 8.

[35] "Why is Ashburn known as 'Data Center Alley?", Upstack, May 18, 2022, available at https://upstack.com/blog/why-is-ashburn-known-as-data-center-alley/.

traditionally the largest electric users.[36] However, data center demand grew rapidly from around 100 MW in 2020 to 600 MW in April 2024.[37] The first hyperscale centers in Central Ohio started to come online in 2017, choosing to locate there because of the reliable electric service, available fiber connectivity, water resources, and retail choice for generation supply. Additionally, Ohio's relatively cool climate attracts data centers and cryptocurrency miners as it reduces the cost of cooling their equipment.[38]

Figure 8: Forecast Data Center Loads by Region, 2027[39]



[36] *See* Direct Testimony of Lisa O. Kelso on behalf of Ohio Power Company, Docket 24-508-EL-ATA, May 13, 2024, ("Kelso Direct Testimony"), at p. 4 (Specifically, AEP's Vice President of Customer Experience testified that "Historically large industrial companies were AEP Ohio's largest users of electricity. For example, as recently as 2006, an aluminum smelting company requiring 520 MW of load was, by far and away, the largest single user for many years… AEP Ohio's largest load began to shift from the historical manufacturing and industrial sectors to the internet and technology sectors, including data centers and crypto currency data mining, starting in the early 2020s.").

[37] Kelso Direct Testimony, at p. 5.

[38] Kelso Direct Testimony, at p. 5.

[39] "The Era of Flat Power Demand is Over," Grid Strategies, December 2023, available at https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf, at p. 10.

The increased demand from new large load customers including data centers is contributing to long wait times for load interconnection requests at utilities across the U.S., including utilities in the Northwest,[40] Midwest[41] and Mid-Atlantic.[42] Several utilities have reported that the expected wait time for connecting new large loads is as long as 7 to 10 years.[43] AEP Ohio has responded to the influx of requests by suspending acceptance of new load service agreements from data center customers, to give the utility time to study the potential impacts of the proposed additions on its transmission and distribution systems.[44] Other utilities have responded by filing requests for new tariffs to recognize data centers and cryptocurrency mining companies as new customer classes required to enter into long-term contracts with the utilities.[45] These multi-year agreements are intended to support utilities' transmission planning as well as the recovery of costs associated with system upgrades made to accommodate the new loads.[46]

Load interconnection delays for new large loads reflect both the speed with which the utility can study potential reliability impacts and the time needed to implement any investments in transmission upgrades to maintain reliable

[40] For example, the Grant Public Utilities Department ("PUD") in Central Washington had 75 applications for 2,897 MW of total peak demand, as of August 2024. About half of the requests are from data centers. *See* "Quarterly Update Large Power Solutions," Grant PUD, August 27, 2024, available at https://www.grantpud.org/block/documents/66c7cc95433a9-2024-08-27-presentation-packet.pdf, at p. 49.

[41] Kelso Direct Testimony, at p. 5 ("…by April 2024, actual data center load was approximately 600 MW in Central Ohio. Data center load…will reach a total of 5,000 MW in Central Ohio by 2030 based on signed agreements with the Company [AEP Ohio]. Central Ohio's total load will more than double from approximately 4,000 to 9,000 MW over the course of a decade…").

[42] Olivo, A., "Internet Data Centers are Fueling Drive to Old Power Source: Coal," The Washington Post, April 17, 2024, available at https://www.washingtonpost.com/business/interactive/2024/data-centers-internet-power-source-coal/.

[43] Grant PUD estimates a wait time of 7-10 years. Dominion Energy expects the time it takes to connect large data centers to the electric grid to increase by one to three years amid a surge in requests, bringing the total wait time to as long as seven years. The longer wait time applies only to requests from large data centers that need more than 100 MW of electricity and have not already been evaluated. AEP Ohio has stated that, because Central Ohio lacks RTO-controlled generation, serving new data center load will require investment in extra high voltage transmission to import power from other parts of the grid. That investment, AEP says, could take 7-10 years to plan, design, site, and construct. *See* "Load at a Glance," Western Electricity Coordinating Council ("WECC"), Updated September 2024, available at https://feature.wecc.org/soti/topic-sections/load/index.html; "Data Centers Face Seven-Year Wait for Dominion Power Hookups," Bloomberg, Updated August 30, 2024, available at https://www.bloomberg.com/news/articles/2024-08-29/data-centers-face-seven-year-wait-for-power-hookups-in-virginia?embedded-checkout=true; Direct Testimony of Kamran Ali on behalf of Ohio Power Company, Public Utilities Commission of Ohio Docket No. 24-508-EL-ATA, May 13, 2024, ("Ali Direct Testimony") at pp. 6-8.

[44] Ali Direct Testimony, at pp. 6-8 ("In March of 2023, AEP implemented a temporary moratorium or pause on taking new service requests from data center customers and executing agreements to move forward with serving that load. This moratorium was taken to allow AEP's transmission planning group time to study the impacts that the additional data center load requests will have on the electrical delivery system in central Ohio to ensure that the grid can reliably serve the new and existing load. Other types of loads, including manufacturing, organic distribution growth (i.e., residential and commercial), and other non-hyperscale level loads, continue to be evaluated to better provide opportunities for job growth and controlled expansion of existing delivery points.").

[45] *See, e.g., In the Matter of the Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers*, Public Utilities Commission of Ohio Docket No. 24-508-EL-ATA, May 13, 2024; Howland, E., "FERC Rejects Basin Electric's Cryptocurrency Mining Rate Proposal," Utility Dive, August 21, 2024, available at https://www.utilitydive.com/news/ferc-basin-electrics-cryptocurrency-bitcoin-mining-rate-proposal/724811/.

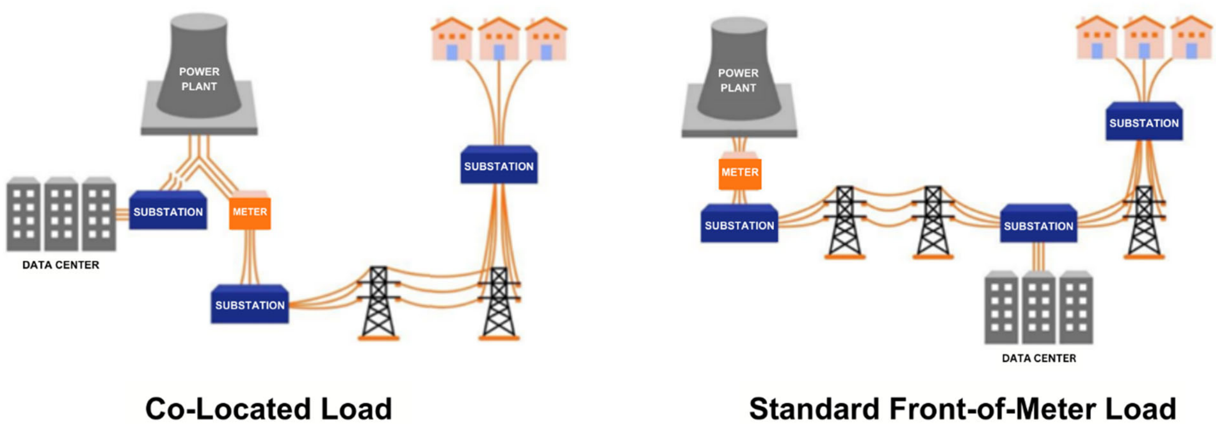
[46] *See, e.g., Direct Testimony of Matthew S. McKenzie on behalf of Ohio Power Company*, Public Utilities Commission of Ohio Docket No. 24-508-EL-ATA, May 13, 2024, at p.19 ("The 90% minimum demand [charge] and ten-year contract (with exit fee) provisions are not meant to perfectly align with investment cost recovery… On the one hand, the data center tariff commitments should be high enough that they provide strong incentives for data centers to follow through with their plans. The commitments should also be high enough that they provide substantial offsetting revenue to pay for necessary investments.").

operations.[47] This has incentivized some cryptocurrency mining facilities, which do not need to be near population centers, to locate in rural areas where transmission capacity is more readily available.[48]

D. Co-Located Loads

One approach used by data centers and cryptocurrency mining operations to obtain electricity service is to "co-locate" the loads with generation facilities. With co-location, the load is physically connected to an existing or planned generating facility behind the meter that measures the flow of electricity from the generator to the distribution or transmission network.[49] Co-location is one of many configurations with both load and generation behind the meter; others include co-generation facilities, distribution energy resources ("DERs"), and microgrids. The difference between co-location and load connected directly to the network is illustrated in **Figure 9**. Under co-location, generation does not require the network to deliver electricity to the co-located load. By contrast, when load is connected directly to the network (via a substation), the network is used to deliver output from the generation facility (or other facilities on the network) to the load.

Figure 9: Alternative Load Configurations: Front-of-Meter Load and Co-Located Load[50]



[47] *See* Ali Direct Testimony, at p. 8 ("To date, AEP Ohio has committed to connect all of the additional load that it could reliably connect to the existing transmission grid… any new demand… will heavily tax the [extra-high-voltage] network bringing electricity into central Ohio. This infrastructure is not only very costly to construct, but it also requires significant time to build based on the distance to meaningful generation supply hubs.").

[48] This is the case for both co-located loads and loads located on the network. For example, cryptocurrency mining facilities have located on or near former electricity generation station sites in rural parts of Central Ohio that were abandoned after deregulation and where transmission capacity is readily available. *See* Kelso Direct Testimony, at pp. 5-6.

[49] PJM uses the term "co-located load" to refer to an "end-use customer load that is physically connected to the facilities of an existing or planned [generating facility] on the Interconnection Customer's [Wholesale Market Participant's] side of the Point of Interconnection." *See* PJM Guidance on Co-Located Load, Posted March 22, 2024, Updated April 17, 2024, available at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/pjm-guidance-on-co-located-load.ashx ("PJM Co-Located Load Guidance"), at p. 1.

[50] Figure is modified from Kormos, M., "The Co-Located Load Solution", Nuclear Energy Institute, July 2024, available at https://www.nei.org/www.nei.org/files/26/2679b7cf-cb96-4aaf-b360-a0af3ec0a381.pdf.

Co-location can involve pairing any type of power plant with any large load, though different loads may prefer different types of generators depending on the quality of power needed for operations. For example, large industrial or data center loads may prefer generators that produce steady, reliable electricity, with high levels of redundancy to ensure that critical business operations remain uninterrupted in the event of a hardware failure or power outage.[51]

Co-locating load with generation can offer certain technical and economic benefits, depending on the physical and contractual configuration of the facility. Co-location may provide more efficient and reliable service to the data center given the immediate connection between generation and load.[52] In addition, co-location can increase the resilience of the grid in the face of outages related to transmission and distribution services.[53] In co-location arrangements where the load is connected to newly interconnected generation supply, the co-located load may earn revenues by providing excess supply to local utilities during periods of peak demand.[54] If this new generation supply is a zero-emissions resource, then the co-location arrangement may help the load customer meet its corporate sustainability targets.[55] For co-location configurations that allow for consumption of electricity from the grid, co-location maintains the option to either consume electricity from the co-located generation source or from the grid, which can lead to economic savings through lower costs.[56]

Co-location differs in the extent to which the co-located load relies on the transmission system for the delivery of energy and capacity in the event of a planned or unplanned outage or during periods where the demand from the load exceeds the coincident production of the on-site electric supply. We refer to a configuration where load may

---

[51] Zhang, M., "Data Center Power: A Comprehensive Overview of Energy," DGTL Infra Real Estate 2.0, March 25, 2024, available at https://dgtlinfra.com/data-center-power/.

[52] For example, co-generation systems avoid transmission and distribution losses that occur when electricity travels over power lines. By avoiding losses associated with conventional electricity supply, "[co-generation] further reduces fuel use, helps avoid the need for new transmission and distribution infrastructure, and eases grid congestion when demand for electricity is high." *See* "CHP Benefits," Environmental Protection Agency, available at https://www.epa.gov/chp/chp-benefits.

[53] Co-generation systems and microgrids can be designed to operate independently from the main electric grid to enhance facility reliability. In addition to enhancing reliability, such systems can be designed to continue operating in the event of a disaster or grid disruption to provide power for critical functions, thereby enhancing grid resiliency. *See* "NARUC Manual on Distributed Energy Resources Rate Design and Compensation," National Association of Regulatory Utility Commissioners ("NARUC"), November 2016, available at https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0, at pp. 46, 48.

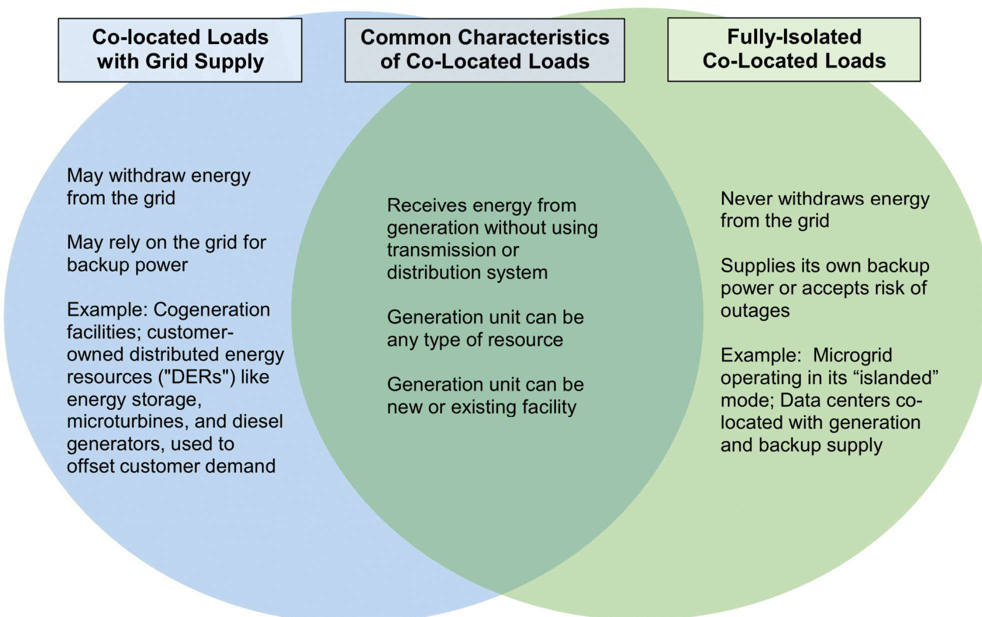
[54] In 2016, the Public Service Commission of Wyoming approved a new tariff designed by Microsoft and Wyoming utility Black Hills Energy. The tariff allows Black Hills Energy to purchase electricity from the backup supply at data centers to meet its peak demand. The tariff is also available to customers with a load of over 13 MW. *See* Trabish, H. K., "How Microsoft and a Wyoming utility designed a data center tariff that works for everyone," Utility Dive, December 20, 2016, available at https://www.utilitydive.com/news/how-microsoft-and-a-wyoming-utility-designed-a-data-center-tariff-that-work/430807/.

[55] Many companies have made commitments to reducing their carbon footprints, with some striving to consume 100% zero-emissions electricity. Examples include members of RE100, a global corporate renewable energy initiative with hundreds of members that are committed to 100% renewable electricity. *See* "10 Years of RE100," Climate Group RE100, available at https://www.there100.org/.

[56] This practice has been reported by at least one cryptocurrency mining company that owns both power plants and mining data center operations in RTOs. *See*, *e.g.,* Stronghold Digital Mining INC, 2023 Form 10-K, available at https://ir.strongholddigitalmining.com/static-files/d2895726-7a10-4af9-9dc0-fc308bbaa1b3, at p. 55 ("We believe that our integrated model of owning our own power plants and Bitcoin mining data center operations helps us to produce Bitcoin at a cost that is attractive versus the price of Bitcoin, and generally below the prevailing market price of power that many of our peers must pay and may have to pay in the future during periods of uncertain or elevated power pricing… Should power prices weaken to a level that is below the Company's cost to produce power, we have the ability to purchase power from the PJM Interconnection Merchant Market…to ensure that we are producing Bitcoin at the lowest possible cost.")

rely on the transmission or distribution system for delivery of energy and capacity as “co-located load with grid supply” and load that does not rely on the transmission system or distribution as “fully-isolated co-located load.” The key distinction between the two is that a fully isolated co-located load never withdraws energy from the grid. The differences are summarized in **Figure 10** and discussed in more detail below.

Figure 10: Types of Co-Located Load Configurations



1. Co-Located Load with Grid Supply

A co-located load with grid supply can rely on network supply to meet power needs during periods when on-site generation is insufficient to meet on-site loads. Under this configuration, (1) the co-located load is served by the co-located generation through electrical facilities located behind the generator’s meter with the RTO, thereby partially or fully meeting the load’s energy needed under typical operations; and (2) the co-located load may draw energy (and capacity) from the network under normal operations, if the facility load exceeds installed generation capacity, or periodically, if, for example, the installed generation experiences a scheduled or unscheduled outage.

Thus, a co-located load may rely on the network if the load exceeds the installed on-site generation or the facility does not have a backup power supply, and thus depends on the grid to provide power during planned or unplanned outages of the generating unit. By maintaining a grid connection, the load can draw electricity when needed, ensuring continued operations while benefiting from the potential efficiency and cost savings of on-site generation. These facilities are usually referred to as partial requirements service or standby service customers and they purchase such service from a load-serving entity (i.e., either the local distribution utility or a competitive retailer).

An example of a co-located load with grid supply is a co-generation facility, which produces both power and thermal energy used for heating or cooling from a single fuel source. Co-generation facilities are primarily used in energy-intensive manufacturing, especially those that generate combustible byproducts, such as chemicals, petroleum refining, and paper industries. However, potential applications are much broader.[57] Other examples include customer-owned DERs like solar, wind, energy storage, microturbines, and diesel generators used to offset customer demand.

2. Fully-Isolated Co-Located Load

A fully isolated co-located load is configured such that it never withdraws energy or capacity from the network. Under this configuration, (1) the co-located load is served by the co-located generation through electrical facilities located behind the generator's meter with the transmission or distribution system; and (2) the co-located load must separate from the generator in the event of a loss of generation output at the plant so that the load does not inadvertently take service from the transmission or distribution system in the event of a generator outage. All costs of new electrical facilities may be borne by co-located entities, including any facilities needed to connect the load to the generation and any system upgrades to ensure reliability is not materially affected by the changes in the generator's interconnection.[58]

To operationalize full isolation, the facility installs equipment designed to automatically disconnect the load in the event that the co-located power supply trips (*i.e.,* experiences an unexpected outage) to ensure that the load does not draw energy from the network. To maintain continued operations, the load may have co-located backup resources, such as battery storage or backup generators, to provide power in the case of planned or unplanned outages at the on-site generator.

An example of a fully-isolated co-located load is Talen Energy and Amazon Web Services' proposed arrangement at Talen Energy's existing Susquehanna nuclear power station.[59] Under this configuration, the co-located load is served by the co-located Susquehanna plant through electrical facilities located behind the generator's meter with the transmission system, and the co-located load must separate from the plant in the event of a loss of generation

[57] "Combined Heat and Power Technology Fills an Important Energy Niche," EIA, October 4, 2012, available at https://www.eia.gov/todayinenergy/detail.php?id=8250.

[58] For example, PJM conducts necessary studies to "evaluate the potential reliability impact of a proposed addition or reduction of a co-located load configuration on the PJM Transmission System, and determine what, if any, system reinforcements are required." If the results of the necessary studies process identify the need to construct system reinforcements, then a Construction Service Agreement may be executed, and the related PJM service agreement would be updated to reflect the necessary system upgrades and related costs. The amended Susquehanna ISA assigns cost responsibility for its necessary system upgrades to the interconnection customer (e.g., the co-located load facility). *See* PJM Co-Located Load Guidance, at p. 5; Susquehanna ISA, Attachment A, Section 10.1 and Schedule F, Part B.

[59] Walton, R., "Constellation, Vistra and PSEG could be next to ink nuclear-data center supply deals: S&P," Utility Dive, June 18, 2024, available at https://www.utilitydive.com/news/constellation-vistra-pseg-nuclear-data-center/719206/.

output so that the load does not inadvertently take service from the grid.[60] Another example of a fully-isolated co-located load is a microgrid operating in its "islanded" mode.[61]

E. Trends in Co-Location

To evaluate the potential impacts of co-located load growth, it would be helpful to have a sense of how much load may co-locate with generation and the extent to which those loads are expected to rely on grid supply. While data on the topic are scarce,[62] the few data points that are available suggest that only a small fraction of large loads will be configured as fully-isolated co-located loads. For example, PJM periodically reports data on co-located load requests, broken down into co-located loads with grid supply and fully-isolated co-located loads. As of April 2023, PJM reported a total of 4,615 MW of co-located load requests, 3,906 MW (85%) of which were for fully-isolated co-located loads.[63] For comparison, PJM predicts systemwide summer peak load to increase by 21,074 MW by 2030, implying that the co-located load requests comprise less than 25%of the total forecasted load growth.[64] Similarly, the Electric Reliability Council of Texas ("ERCOT") reported that 9,885 MW out of 56,954 MW (17%) of large load requests were for co-located load projects as of September 2024.[65] The rest are for standalone projects, suggesting that new load will primarily be served by the grid.

In addition to co-locating with existing generation units, large load customers are building new generation to meet their needs. For example, several data center developers have announced plans to use small modular reactors

[60] Susquehanna ISA Attachment A, Schedule F, Part B and Part E.

[61] "A microgrid is a group of interconnected loads and distributed generation that act as a single controllable electrical entity and can operate in both grid-connected and isolated modes" in order to "provide independent power to designated critical loads upon loss of their primary source of energy." A microgrid may be considered a fully-isolated co-located load while it is operating in its isolated ("islanded") mode during which it does not rely on power from the grid. *See* Booth S. et al., "Microgrids for Energy Resilience: A Guide to Conceptual Design and Lessons from Defense Projects," National Renewable Energy Laboratory, May 2019, Revised January 2020, available at https://www.nrel.gov/docs/fy19osti/72586.pdf, at pp. 1, 3-4.

[62] Data on large load requests is not systematically reported across RTO/ISOs and may not be an accurate predictor of load growth because some requests could eventually be withdrawn. Also, it is not always reported whether co-located loads will be served by new or existing generation units or whether loads will rely on the grid for backup supply.

[63] PJM, "Co-Located Load Requests," April 12, 2023, available at https://www.pjm.com/-/media/committees-groups/committees/mic/2023/20230412/20230412-item-09---informational-only---current-co-located-load-requests.ashx, at p.2.

[64] PJM load growth forecasts include adjustments for growth in data center load in several PJM zones. *See* PJM Resource Adequacy Planning Department, "PJM Load Forecast Report," Tables B-1 and B-9, January 2024, https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx, at pp. 1, 35.

[65] ERCOT does not report whether co-located loads are configured to rely on the grid for backup supply. *See* ERCOT, "Large Load Interconnection Status & Analytics Update", September 6, 2024, https://www.ercot.com/files/docs/2024/09/05/LLI%20Queue%20Status%20Update%20-%202024-9-6.pdf, at p. 2.

("SMRs"),[66] which are advanced nuclear reactors with a power capacity of up to 300 MW.[67] Other projects in development include data centers powered by off-grid, "high-tech fuel cells that convert natural gas into low-emissions electricity," and projects that are powered by geothermal energy and supplemented with grid power.[68]

Although growth in fully-isolated co-located loads is limited to date, concerns have emerged regarding potential market price impacts (particularly given gradual and sudden increases in prices due to the cumulative effect of policy objectives), the ability of utilities and grid operators to maintain reliable system operations while accommodating new loads, and the allocation of the often substantial costs associated with investing in the infrastructure needed to service new loads (while simultaneously investing in new transmission infrastructure needed to support the energy transition).[69] The remainder of this paper explores these issues in greater detail.

III. Market and Reliability Impacts

As with any market, an increase in electricity demand will tend to increase prices for wholesale electricity in the short- and long-run, as increased demand requires more costly energy, capacity, and ancillary services (at the margin). In principle, new loads can also adversely affect resource adequacy if the growth in customers' loads outpaces the development of new resources, although all systems maintain markets, processes and procedures to ensure reliable operations in the face of such changes in system demands and resources. However, whether a new load is co-located with an existing generator or is located on the system, energy and capacity market

[66] Wong, W., "Going Nuclear: A Guide to SMRs and Nuclear-Powered Data Centers," Data Center Knowledge, November 29, 2023, available at https://www.datacenterknowledge.com/energy-power-supply/going-nuclear-a-guide-to-smrs-and-nuclear-powered-data-centers#close-modal.

[67] In October 2024, Google and Kairos Power announced plans to deploy a U.S. fleet of advanced nuclear power projects totaling 500 MW by 2035. In August 2023, IP3 and Corporation and Green Energy Partners announced joint plans for a project in Surry County, Virginia, that will use four to six SMRs to power 20 to 30 data centers, generate hydrogen fuel and provide backup power for Virginia's grid. In October 2023, Standard Power announced plans to develop two SMR-powered facilities in Ohio and Pennsylvania that will provide nearly 2 GW of carbon-free electricity to power nearby data centers. These projects may or may not rely on the grid for backup supply. *See* "Google and Kairos Power Partner to Deploy 500 MW of Clean Electricity Generation", Kairos Power, October 14, 2024, available at https://kairospower.com/external_updates/google-and-kairos-power-partner-to-deploy-500-mw-of-clean-electricity-generation/; "IP3 and Green Energy Partners Sign Agreement to Jointly Pursue Large-Scale Green Data Center Facility and Surry Green Energy Center," IP3, available at https://www.ip3international.com/ip3-and-green-energy-partners-sign-agreement-to-jointly-pursue-large-scale-green-data-center-facility-and-surry-green-energy-center/; "Standard Power Chooses NuScale's Approved SMR Technology and ENTRA1 Energy to Energize Data Centers," NuScale, October 6, 2023, available at https://www.nuscalepower.com/en/news/press-releases/2023/standard-power-chooses-nuscales-approved-smr-technology-and-entra1-energy-to-energize-data-centers.

[68] Halper, E., "Amid explosive demand, America is running out of power," The Washington Post, March 7, 2024, available at https://www.washingtonpost.com/business/2024/03/07/ai-data-centers-power/.

[69] *See, e.g.,* Exelon/AEP Protest, at pp. 3-4; Reed and Powers Declaration, at p. 3; Anderson, J. and A. Good, "FERC Sends PJM Deficiency Letter Over Proposed Deal to Supply Data Center with Nuclear Power," S&P Global, August 5, 2024, available at https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/electric-power/080524-ferc-sends-pjm-deficiency-letter-over-proposed-deal-to-supply-data-center-with-nuclear-power.

outcomes will generally not depend on whether or not the loads are co-located (holding quantity and location fixed). There is general agreement on this point.[70]

While market impacts will generally be similar, some differences can emerge. For capacity markets, fully-isolated co-located load would experience smaller impacts because they do not require the reserve margin that must be procured for loads located on-the-network. For ancillary services, holding quantity and location constant, co-locating a new load will have the same impact on system costs as supplying the load from the system (which in some cases may be zero).

With respect to reliability, both co-located and grid-supplied load can impact system reliability, and the potential impacts will be specific to the load's location under each scenario. However, under either interconnection arrangement, the transmission operator and/or transmission/distribution owner would study the reliability impacts associated with the addition of the load, and needed upgrades to the system would be made such that reliability would not be diminished.

A. Energy and Capacity Market Outcomes

Like any market, an increase in demand will tend to increase prices, all else equal. The additional demand requires that the market clear supply with higher offers to provide energy or capacity. This effect is the same whether new load is co-located or located on the network, as increasing load affects the supply-demand balance in the same way in either case. For example, **Figure 11** provides a stylized depiction of energy market clearing with new load co-located (red) or located on the network (aqua).[71] If the potential co-located generator is inframarginal (such that its marginal cost is below the market clearing price), then increasing demand (shifting the demand curve to the right) has the same impact on price as decreasing supply (shifting the supply curve to the left).[72]

With the capacity market, the change in demand and supply are not symmetric, resulting in a smaller increase in prices when loads are co-located. While the reduced supply would reflect the size of the co-located load, the increased demand would reflect the co-located load plus the capacity market reserve margin.[73] For example, if a co-located load is 500 MW, then this would cause the supply of capacity to shift to the left by 500 MW. However, if

[70] *See, e.g.,* Duane and Clark II, at p. 9, ("We agree with NEI that while the interconnection of colocated load will (all things being equal) drive up energy and capacity prices in the wholesale market; this is a function of supply and demand and no different from load connecting in the traditional manner.").

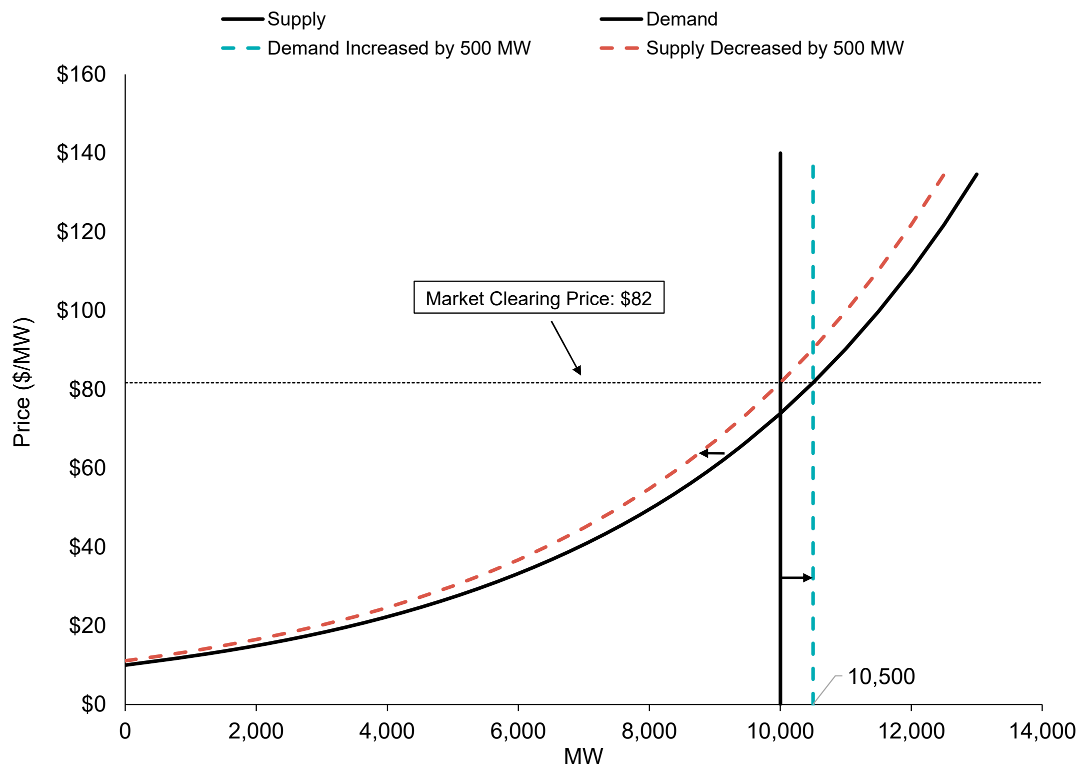
[71] The figure assumes infra-marginal supply with low short-run marginal costs and/or large commitment costs, such as a nuclear energy facility. The figure also assumes inelastic demand, including inelastic demand from the large load. In practice, some large loads may be price responsive if the value of energy to the customer is less than the price. This is often the case for cryptocurrency mining facilities, which have the ability to reduce production on short notice and which can become unprofitable when prices too high.

[72] Co-located loads could contract with a resource whose marginal cost is at times above the market clearing price. If such arrangements involve loads that also receive network supply, the loads can purchase power from the market rather than the co-located generator when doing so would be less expensive.

[73] The capacity market reserve margin reflects the quantity of additional capacity procured to maintain resource adequacy in excess of the expected peak system load. This reserve margin is reflected in various ways, including an explicit percentage reserve margin (e.g., NYISO) or a capacity requirement that accounts for the need for a capacity reserve in excess of expected peak system load (e.g., ISO-NE, PJM). *See, e.g.,* Owain, J. and A. McHich, "Introducing the NYISO Electricity Capacity Market," CME Group, June 25, 2018, available at https://www.cmegroup.com/education/articles-and-reports/introducing-the-nyiso-eletricity-capacity-market.html.

that same load were located on the network, the capacity market would procure a greater quantity of capacity (e.g., 575 MW if the reserve margin is 15%). Because the size of the shift in demand is greater than the shift in supply, the co-located load results in a *smaller* price increase compared to the load located on the network.

Figure 11: Increasing Demand (by Adding New Grid-Supplied Load) or Decreasing Supply (by Co-Locating New Load at an Existing Low-Cost Generator) Has the Same Effect on Price



While any new demand would be expected to, at the margin, raise prices, actual impacts and whether they would differ between co-location and interconnection on the system will depend on many factors specific to the location of load on the system, including, among other things, the specific location of the co-located load and where the load would otherwise hypothetically interconnect, preexisting system energy flows, the congestion and local reliability issues in each location, and the needs placed on the system by the co-located and on-the-system loads (given differences in on-site configurations).

B. Ancillary Services Impacts

Ancillary services are additional services provided by system resources to maintain reliable system operations, such as online and offline operating reserves, regulation and frequency response, voltage control, and black start service, among others.[74] Operating reserves and regulation and frequency response are typically supplied through a market mechanism in RTO/ISO markets while the other services are procured by the market operator or automatically supplied by certain generators.[75] Ancillary services requirements are very low relative to system load and are largely set independent of system load. Ancillary services represent a small fraction of power system operational costs, typically comprising less than 2% of total power supply costs for most RTO/ISOs.[76]

Under some configurations, certain ancillary services may be self-supplied by the co-located load (e.g., voltage control). Moreover, the co-located generation may continue to provide certain ancillary services to the grid, as well as the co-located load, such as regulation and frequency response and voltage control, even if the energy and capacity are committed to the co-located load.[77]

1. Operating Reserves

Operating reserves represent additional online and offline supply resources that are available to provide energy (or demand resources available to reduce its output) to meet expected or unexpected fluctuations in supply and demand to ensure that the system supply-demand balance is maintained.[78] RTO/ISOs set operating reserve requirements based on the "most severe single contingency" outage that could take place during system operation.[79] Operating reserve requirements vary across the power system operators, but generally the online contingency reserve requirements range from several hundred MW to just over 2,000 MW.[80]

Thus, in these RTO/ISOs, the required amount of contingency reserves is unrelated to the addition of new load, unless the co-located load affects the definition of the largest single contingency.[81] Finally, although system

---

[74] "Ancillary Services in the United States: Technical Requirements, Market Designs and Price Trends," EPRI, 2019, available at https://www.epri.com/research/products/000000003002015670, ("EPRI Ancillary Services Report"), at pp. 1-3 to 1-4.

[75] EPRI Ancillary Services Report, at pp. 2-1, 2-14, 3-13 to 3-14.

[76] Between 2019-2022, ancillary services costs as a share of total wholesale power costs were 1.2% for ISO-NE, 1.5% for CAISO, 1.5% for MISO, 1.5% for PJM, 4.4% for SPP, and 5.3% for NYISO. *See* "Table 9: Wholesale Power Costs by Charge Type, 2023 Common Metrics," FERC, January 31, 2024, available at https://www.ferc.gov/media/2023-common-metrics.

[77] EPRI Ancillary Services Report, at pp. 2-13 to 2-17.

[78] There are several types of operating reserves, including contingency reserves, flexibility reserves, and regulating reserves, each designed to meet a different need, and each RTO/ISO has defined a unique set of reserves to meet its needs. *See* EPRI Ancillary Services Report, at pp. 1-4, 2-1.

[79] In CAISO and ERCOT, the size of the reserve requirements is a function of load and solar generation (CAISO) or load and wind generation (ERCOT). *See* EPRI Ancillary Services Report, at p. 2-3. *See also* PJM, "PJM Education on Reserve Practices across RTO/ISOs," December 12, 2023, available at https://www.pjm.com/-/media/committees-groups/task-forces/rcstf/2023/20231212/20231212-item-03---comparison-of-reserve-practices-across-rtos.ashx.

[80] "2023 State of the Market Report for PJM," Monitoring Analytics, March 14, 2024, available at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023/2023-som-pjm-sec10.pdf, at pp. 533-534; NYISO, "NYISO Locational Reserve Requirements," available at https://www.nyiso.com/documents/20142/3694424/Locational-Reserves-Requirements.pdf; CAISO, "2023 Annual Report on Market Issues & Performance," July 29, 2024, available at https://www.caiso.com/documents/2023-annual-report-on-market-issues-and-performance-jul-29-2024.pdf, at pp. 195-197; MISO, "Short Term Reserve," November 2, 2021, available at https://cdn.misoenergy.org/20211102%20STR%20Workshop%20Presentation%20(IR010)600624.pdf, at p. 10.

[81] In ERCOT and CAISO, if load is co-located and measured net of on-site generation, contingency reserve requirements may be lower than if the load is served by the system. *See* EPRI Ancillary Services Report, at pp. 2-3.

operators continue to evaluate reserve products to account for increased intermittent resource supply (and other factors), in practice, the reserve response requirements have been small, in the hundreds of MW.[82]

2. Regulation and Frequency Response

Regulation and frequency response allows for continuous balancing of generation supply and load and the maintenance of system frequency at 60 cycles per second (Hz).[83] Regulation and frequency control requirements are set based on system operator experience to ensure that system resources are available to respond to second to second and fraction of second changes in system supply and demand. Regulation and frequency control requirements vary seasonally, monthly and hourly, and are small relative to system load. For example, they range between 525 MW to 800 MW in PJM, 400 MW to 900 MW in CAISO, and 175 MW to 350 MW in NYISO.[84] As such, co-located load may not impact the calculated reserve requirement, particularly if load is measured net of on-site generation, whereas grid-supplied load could lead to a small change in the requirement if it its energy needs are sufficiently variable. Moreover, even if the requirement is calculated symmetrically for co-located and grid-supplied load, the amount of regulating reserves needed by the system would not change if the new load has a stable load profile, or if the load is co-located with a load-following generator. Thus, co-locating load, relative to supplying load from the system, is likely to have little to no impact on the regulating reserve requirement.

3. Voltage Control and Black Start Service

Voltage control is provided by reactive power supply, which is in turn provided by generators, various transmission assets and loads to help maintain power system voltage within a certain band.[85] Coal, natural gas, nuclear, wind, solar, and batteries can all provide voltage control.[86] Reactive power sources such as capacitor banks and static VAR compensators can also be installed at load locations and on the transmission system to provide voltage support. Reactive power supply is a very localized service that must be located near where it is consumed.[87] Thus, co-located load may receive voltage control service directly from the generator serving it (or other reactive power sources behind the meter) as the generator will continue to provide voltage support at its interconnection point. As such, adding a new load behind the generator's meter can be configured to neither change the voltage support needs of the system, nor the generator's ability to provide voltage support to the rest of the system.

---

[82] For example, flexibility reserve products are used by some RTO/ISOs to help respond to unexpected variation in wind and solar generation with reserve requirements generally set based on the expected variations. *See* EPRI Ancillary Services Report, at pp. 2-11.

[83] Regulation is the small increments of generating capacity from resources that can respond within seconds that are used to maintain power balance on the system in real-time and frequency response is the automatic stabilizing response of generators and demand response resources to variations in frequency. *See* EPRI Ancillary Services Report, at pp. 1-3, 2-7 to 2-10, and 2-14.

[84] "2023 State of the Market Report for PJM," Monitoring Analytics, March 14, 2024, available at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023/2023-som-pjm-sec10.pdf, at p. 535; CAISO, "2023 Annual Report on Market Issues & Performance," July 29, 2024, available at https://www.caiso.com/documents/2023-annual-report-on-market-issues-and-performance-jul-29-2024.pdf, at pp. 196-197; NYISO, "NYISO Regulation Requirements," June 1, 2023, available at https://www.nyiso.com/documents/20142/3694424/nyiso_regulation_req.pdf/6efc0df8-edc2-41bc-9e39-5fed576ba7bc.

[85] *See* EPRI Ancillary Services Report, at p. 2-17; Milligan, Michael, "Sources of Grid Reliability Services," *The Electricity Journal*, 31(9), 2018, pp. 1-7, at pp. 2-3 ("Milligan").

[86] *See* Milligan, at p. 3.

[87] *See* EPRI Ancillary Services Report, at pp. 2-17, 3-14.

Black start service restores the system following a blackout.[88] Resources that can provide black start service include those that can start without support from the system and/or remain operational in a blackout and then assist in re-energizing the system.[89] It is unlikely that a new load would change the system re-energization plan of the transmission owner, which is dependent on the available generation resources with black start capability. However, should there be any change in black start service needs from adding a new load, the cost is the same whether the load is in front of or behind the meter.

C. Reliability Impacts

In principle, new loads, whether co-located or grid-supplied, can impact system reliability. However, to mitigate reliability risks, RTO/ISOs have multiple procedures for maintaining resource adequacy and reliability, including, but not limited to, capacity markets and transmission planning procedures. These processes are intended to adapt the system as new loads are added. Thus, while these procedures could be inadequate to the challenge of adding new resources to meet new demand, thereby leading to impacts on reliability, a more likely outcome is that new loads are interconnected gradually as their impacts are evaluated and any needed transmission system upgrades are made and new supply resources are added.

Whether load is co-located or served by the network, transmission/distribution owners typically study the reliability impacts associated with the addition of the new large loads to determine whether the new load can be accommodated or whether upgrades are needed to the system to maintain reliability. When loads co-locate at a generation facility, requiring amendments to interconnection agreements, RTO/ISOs have the opportunity to, and typically do, perform reliability studies to assess how changes to generation output affect transmission flows and any resulting reliability impacts.[90] If reliability concerns are identified in these studies, transmission system upgrades may be required before the load can be served.[91]

To the extent that reliability impacts for new large loads are identified, service to the load may be delayed until distribution and transmission system reinforcements can be undertaken. For example, some regions that have experienced a large influx of data centers have either imposed a moratorium on new data center loads (e.g., AEP) or experienced delays in providing service to data centers (e.g., Dominion).[92] The costs associated with maintaining system reliability with the addition of new load can differ substantially across locations and these costs may factor into the location decision of the new load if they will bear a substantial amount (or even all) of these costs. As discussed below, the allocation of these costs may differ if loads are co-located versus located on the network.

---

[88] *See* EPRI Ancillary Services Report, at p. 2-17.

[89] *See* EPRI Ancillary Services Report, at pp. 2-17 to 2-18.

[90] For example, the PJM necessary studies process is used to evaluate the potential reliability impact of a proposed addition or reduction of a co-located load configuration. *See* PJM Co-Located Load Guidance, at p. 5.

[91] *See, e.g.,* Susquehanna ISA, Attachment A, Schedule F, Part B.

[92] Ali Direct Testimony, at p. 6; "Data Centers Face Seven-Year Wait for Dominion Power Hookups," Bloomberg, Updated August 30, 2024, available at https://www.bloomberg.com/news/articles/2024-08-29/data-centers-face-seven-year-wait-for-power-hookups-in-virginia?embedded-checkout=true.

IV. Economic Efficiency

The location of loads in relation to generation can have important consequences for the costs of both constructing and operating a reliable grid. Within such a system, reducing the distance between generation and loads can lower both capital and operating costs.[93]

Capital costs are reduced with co-location because less transmission infrastructure, particularly transmission lines, are needed to move power from generation to loads. The economic impact of a particular co-located load (compared to locating loads somewhere on the system) may depend on multiple factors, including the new loads' particular location within the pre-existing grid. However, co-location would be expected to enhance the efficiency of the transmission system and lower the costs of transmission investment, particularly when the rates charged for service are aligned with cost causation and the marginal cost of using the service. We return to this issue in **Section V**.

Closer proximity between generation and loads also reduces energy losses that occur when electricity flows through transmission infrastructure. The EIA estimates that transmission and distribution losses are approximately 5% of energy flowed on the grid.[94] Lower energy losses both reduce operating costs, because less power must be generated to meet customers loads, and reduce capital costs, because less transmission capability is needed to flow energy through the system to meet customer loads. By, in effect, eliminating the distance between generation and load, co-location is consistent with more efficient transmission planning and operation. Thus, limiting co-location as an option for serving data center load would raise costs.

The costs of upgrading the transmission and distribution systems to accommodate new large loads can be substantial. Consequently, potential savings in transmission and distribution infrastructure investment that can be achieved through co-location or other means are important for efficiently meeting the growth in new loads on the grid. Competition among potential suppliers to provide electricity service to data center loads offers opportunities for innovation that may lower costs and improve efficiencies. Rates aligned with cost causation are important to such innovation leading to more efficient outcomes.

Examples of the substantial transmission costs associated with meeting growing loads are rising. PJM's most recent transmission plan identified $5.1 billion in investment to maintain reliability, and identified data centers as a significant driver of these investment costs.[95] In particular, of the $5.1 billion total, $3.2 billion explicitly addresses

---

[93] *See, e.g.* PJM, "Item 4A - Capacity Co-Located Load - Problem Statement, PJM Capacity Offer Opportunities for Generation with Co-Located Load Issue," January 12, 2022, available at https://pjm.com/-/media/committees-groups/committees/mic/2022/20220112/20220112-item-04a-capacity-co-located-load-problem-statement.ashx.

[94] "How much electricity is lost in electricity transmission and distribution in the United States," EIA, November 7, 2023, available at https://www.eia.gov/tools/faqs/faq.php?id=105&t=3.

[95] PJM's 2023 Regional Transmission Expansion Plan ("RTEP") report highlights data center load as a major driver of the $5.1 billion in selected transmission upgrades, but some system upgrades are necessary to accommodate retiring generation resources. *See* PJM, "RTEP 2023," March 7, 2024, available at https://www.pjm.com/-/media/library/reports-notices/2023-rtep/2023-rtep-report.ashx, at pp. 1, 52.

data center load growth, with $2.0 billion alone in transmission system investment for one company – Dominion.[96] Dominion's approved investments were largely (if not solely) to address data center loads located on the system, but not co-located.[97] Other utilities are facing similar growth and potentially high costs.[98] For example, AEP is experiencing growing demand for data centers in Central Ohio, a region "heavily dependent" on transmission.[99] AEP issued a temporary moratorium on service requests for new data centers to evaluate the required investment to accommodate this growing demand, which "is anticipated to be significant."[100]

Similarly, the costs of distribution system upgrades to serve new loads can also be large and existing ratemaking structures may spread those costs across all customers rather than being borne by new loads. For example, Exelon's Illinois subsidiary Commonwealth Edison Company ("ComEd") reported that the average cost per "large load customer" to interconnect to the ComEd electricity distribution system was $11,899,297.[101] Moreover, ComEd reported that "[o]n average, the requesting customer paid $981,392 for each interconnection and $10,917,906 was paid by the rest of ComEd's customers for each interconnection."[102] Here, a "large load customer" is a customer with greater than 30 MW of load, which is substantially smaller than many data center loads. Thus, while the estimate reflects 16 large load customers that are not exclusively data centers,[103] it highlights the recent costs spread to and borne by ComEd's retail customers to interconnect new large loads.

Under certain configurations, co-located loads and generators bear the capital costs associated with their interconnection and the upgrades to the system needed to maintain system deliverability and reliability. By internalizing these costs, these new loads may tend to select locations (among potential co-located and on-the-system sites) that involve lower capital costs in order to interconnect. By contrast, new loads locating on the system, which generally do not directly bear all the costs of interconnecting, would not face such incentives. Thus, for new loads that have greater flexibility about where they can locate, co-location can encourage siting in locations that involve lower incremental costs.

---

[96] PJM, "Reliability Analysis Report: 2022 RTEP Window 3," December 8, 2023, available at https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20231205/20231205-2022-rtep-window-3-reliability-analysis-report.ashx, at pp. 29-30, 36-55, (Proposal IDs 711, 692, 516, 344/660, 837, 853 all relate to data center load growth and debottlenecking transmission into the area.).

[97] "Q1 2024 Earnings Call," Dominion Energy, May 2, 2024, available at https://s2.q4cdn.com/510812146/files/doc_financials/2024/q1/2024-05-02-DE-IR-1Q-2024-earnings-call-slides-vTC.pdf, at p. 14.

[98] *See* "Utility Experiences and Trends Regarding Data Centers: 2024 Survey," EPRI, September 16, 2024, available at https://www.epri.com/research/products/000000003002030643, at pp. 5-6.

[99] Ali Direct Testimony, at p. 8 (Specifically, AEP's Vice President of Transmission Planning and Analysis testified that "The Central Ohio transmission region is heavily dependent on the transmission infrastructure to meet its electricity demand. There is no RTO-controlled generation currently located inside central Ohio and as a result all electricity is imported through the extra high voltage transmission network.").

[100] Ali Direct Testimony, at p. 8 ("[Extra High Voltage] investments are required; […] This infrastructure is not only very costly to construct, but it also requires significant time to build based on the distance to meaningful generation supply hubs.").

[101] Commonwealth Edison Company's Response to Constellation Energy Generation LLC's ("Constellation") Data Request Constellation-ComEd 5.01 RGP – Constellation-ComEd 5.04 RGP, ICC Docket Nos. 22-0486 / 23-0055 (Consol.) Refiled Grid Plan, received May 30, 2024, available at https://www.icc.illinois.gov/docket/P2023-0055/documents/352947/files/617782.pdf (hereafter, "ComEd Response to Constellation").

[102] ComEd Response to Constellation.

[103] ComEd Response to Constellation.

V. Rates for Co-Located Loads

Co-location of loads and generation is not a new phenomenon and FERC has evaluated and approved transmission and ancillary services rates that account for co-location in the past. Despite this precedent, debate has arisen over the rates that should be charged to co-located loads, particularly when the loads are fully isolated from the network. Some have suggested that fully-isolated co-located loads should pay for transmission service and ancillary services and have claimed that failure to pay for these services in one co-location deal could result in a large "cost shift" to existing customers, on the order of $58 million to $140 million annually.[104]

As we show below, these claims are inconsistent with the past and current rates approved by FERC involving co-located loads. These rate structures are consistent across co-location configurations, and include circumstances when co-located loads are smaller than co-located generation, leading to the supply of "excess" generation to the network. These rates are also consistent with sound ratemaking principles, particularly the principle of efficient rates, reflecting marginal costs.

A. Current Tariff Rules and Rates

The appropriate treatment of co-located loads and generation for the purposes of determining charges for transmission and ancillary services has been addressed in the context of many Commission orders, including those that established the foundation of open access to the transmission system. Specific issues related to co-location have arisen in the context of many different kinds of resources and loads, including cogeneration facilities, distributed generation, microgrids, and non-utility entities, such as municipal and cooperative load serving utilities. In this regard, FERC has developed a relatively consistent approach to transmission and ancillary service ratemaking and established tariff language to deal with co-location based on – as we discuss below – sound economic and ratemaking principles.

Across tariffs, several common and explicit themes emerge. *First*, FERC transmission policies aim to provide "open access" to all networks, not to require use of the network. Thus, co-located loads do not need to take network service if they are not using the network for the delivery of energy and capacity. *Second*, the criterion for use of the network is actual withdrawals from the network (i.e., the net of behind-the-meter load and generation). Thus, for example, a fully-isolated co-located load would not face any cost for network transmission service (or ancillary services) because, by design, it would not actually withdraw energy from the network.

Importantly, there is nothing unique about the co-location of digital loads with generation that distinguishes the circumstances of co-location from those that have been addressed previously by the Commission. While concerns have been raised that the scale of co-location of digital loads will have "huge" and "profound" effects,[105] the implications of these concerns is that somehow FERC has been approving unjust and unreasonable rates for more than 20 years but that it just did not matter because the scale of the co-location was small. This is illogical and

[104] *See, e.g.,* Reed and Powers Declaration, at p. 4.

[105] Exelon/AEP Protest, at p. 2.

ignores that the rationale used to determine whether rates are just and reasonable reflects ratemaking principles, such as efficiency and fairness, that do not depend on scale.

1. *Open Access Transmission Tariffs ("OATT") Offer the Option – Not the Obligation – To Use Network Service for Delivery of Energy and Capacity*

The first issue in assessing service for co-located loads is clarifying what service is provided by network transmission service and whether customers are obligated to use network service. In short, network transmission service provides for the *delivery of energy and capacity* between generators and loads. Market participants are *not required* to use this service, but instead *have the option* to use this service. We discuss each of these conclusions in further detail, below. However, the implications for fully-isolated co-located loads are direct and obvious. Because fully-isolated co-located loads receive delivery of energy and capacity from co-located generation, they do not use network transmission service and thus should not be charged for such service.

FERC policy on transmission ratemaking is laid out in Order 888 and related orders. To eliminate barriers to competition in the wholesale bulk power markets, Order 888 required public utilities to provide open access transmission service on a comparable basis to the transmission service they provide themselves.[106] By unlocking this competition, FERC aimed "to bring more efficient, lower-cost power to the Nation's electricity consumers."[107]

To this end, FERC required each RTO/ISO (and transmission utility) to offer transmission service under an OATT, thus providing *the option* for market participants to buy and sell power over a utility-owned transmission system. However, the option to use transmission service under the OATT is not intended *to require* that market participants use the services offered by the network. Thus, Order 888 aimed to preserve competitive options for the trade of electric energy in the bulk wholesale markets and not to deter innovation and competitive responses to the monopoly transmission and distribution network.[108] Data centers should be able to pursue the most economical interconnection service.

With regard to behind-the-meter loads, FERC Order 888-A clarifies that behind-the-meter loads do not need to designate loads as network resources:

> Moreover, the Commission will allow a network customer to either designate all of a discrete load as network load under the network integration transmission service or *to exclude the entirety of a discrete load from*

[106] "History of OATT Reform," FERC, January 18, 2023, available at https://www.ferc.gov/industries-data/electric/industry-activities/open-access-transmission-tariff-oatt-reform/history-oatt-reform.

[107] "History of OATT Reform," FERC, January 18, 2023, available at https://www.ferc.gov/industries-data/electric/industry-activities/open-access-transmission-tariff-oatt-reform/history-oatt-reform.

[108] Order No. 888, 75 FERC ¶ 61,080, issued April 24, 1996, available at https://www.ferc.gov/sites/default/files/2020-05/rm95-8-00w.txt ("FERC Order 888-A"), at p. 1 ("The legal and policy cornerstone of these rules is to remedy undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce.").

> *network service and serve such load with the customer's "behind-the-meter" generation* and/or through any point-to-point transmission service.[109]

That loads have the option but not the obligation to take service is evident in individual RTO/ISO tariffs. For example, the PJM OATT's definition of Network Load states that:

> A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Tariff, Part II for any Point-To-Point Transmission Service *that may be necessary* for such non-designated load.[110]

Thus, FERC ratemaking is clear that loads should not be required to take network transmission service for the delivery of energy.

Regarding what is provided by transmission service, FERC-regulated RTO/ISO tariffs consistently define network transmission service[111] as service providing the delivery of either *energy* alone (CAISO and NYISO) or *energy and capacity* from generators to loads (ISO-NE, MISO, PJM, SPP). Thus, network transmission service is specific to the delivery of capacity and energy, not ancillary services, which we discuss separately below. This research is summarized in **Table 1** in **Appendix A** of this paper, which provides the definition of network transmission service for each FERC-regulated RTO/ISO. For example, PJM's OATT defines Network Integration Transmission Service as "firm transmission service over the Transmission System to the Network Customer for *the delivery of capacity and energy* from its designated Network Resources to service its Network Loads on a basis that is comparable to each Transmission Owner's use of the Transmission System to reliably serve its Native Load Customers."[112] Other RTO/ISOs use similar definitions.

Given this standard, an initial assessment of co-located loads must consider whether the configuration involves the delivery of energy (or energy and capacity) from network resources to the co-located loads. For fully-isolated co-located loads, this is not the case – that is, a fully-isolated co-located load is configured to avoid ever taking delivery of energy (or capacity) from the network and to instead rely solely on the energy from the co-located

---

[109] FERC Order 888-A, at p. 251. Relatedly, comments provided to the FERC on the amended Susquehanna ISA mischaracterize FERC's position on co-location. In its Response, AEP and Exelon reference FERC's limitation on the use of a "split system", where a discrete point of delivery receives energy and capacity through both network and point-to-point transmission service. FERC's findings on service for "split system" clearly reference transmission service that "splits" loads at a particular interconnection, not the netting of generation and load behind a given interconnection. *See Joint Protest of Exelon Corporation and American Electric Power Service Corporation to PJM Deficiency Response,* PJM Interconnection, L.L.C., FERC Docket No. ER24-2172-001, at p. 21 ("The concept of allowing a "split system" or splitting a discrete load is antithetical to the concept of network service. A request for network service is a request for the integration of a customer's resources and loads. Quite simply, a load at a discrete point of delivery cannot be partially integrated—it is either fully integrated or not integrated. Furthermore, such a split system creates the potential for a customer to "game the system" thereby evading some or all of its load-ratio cost responsibility for network services.").

[110] Emphasis added. PJM OATT, Section I.1, OATT Definitions L – M – N, Network Load Definition, available at https://pjm.com/directory/merged-tariffs/oatt.pdf ("PJM OATT").

[111] Many RTO/ISOs refer to network transmission service as Network Integration Transmission Service ("NITS").

[112] PJM OATT, Section 28.3.

generation.[113] Thus, as no energy (or capacity) is delivered, this implies that no network transmission service is required. Existing facilities are operating under this ratemaking structure, including the Susquehanna nuclear facility (which has received approval for co-located loads prior to the incremental loads contested in recent proceedings) and a facility with fully-isolated co-located load in NYISO operated by Greenidge Energy.[114] To the extent that there is excess supply from the co-located generation, this can then be supplied to the network.

2. *RTO/ISO Ratemaking For Co-Located Generation and Load Is Based on Netting of Injections and Withdrawals*

The second key issue relevant to determining ratemaking for co-located loads is how charges are assessed. As we show, in most (if not all) circumstances, co-located loads are charged for network transmission service based on their use of the network on a net rather than a gross basis. Thus, when co-located loads exceed co-located generation, charges are based on the actual withdrawals of energy from the network, rather than the behind-the-meter gross load. Similarly, when co-located generation exceeds co-located loads, the excess generation can be supplied to the grid. Thus, under this approach to measuring use and charging for service, a fully-isolated co-located load would incur no charges at all times, consistent with the conclusion that it is not taking service.

Based on our research, across RTO/ISOs, a common practice when assessing charges for network transmission service is to do so on the basis of actual withdrawals from the network (i.e., gross behind-the-meter load net of behind-the-meter generation) rather than on the basis of gross behind-the-meter load.[115] **Table 2** in **Appendix A** summarizes our research, describing the billing determinants used to assess transmission service charges across RTO/ISOs. For example, when filing its Tariff Revisions, PJM stated:

> Simply put, the new behind the meter generation market rules will permit an entity serving load with behind the meter generation that is operating and serving load at the same, single electrical location to net such generation against load for the purposes of calculating the charges for various services under the PJM agreement . . . In the event there is more behind the meter generation than load or the behind the meter

---

[113] *See, e.g.,* Susquehanna ISA, Attachment A, Schedule F, Part F.4 ("The Co-Located Load is not Network Load, and it is intended that the Co-Located Load will never consume capacity and/or energy from the PJM Transmission System, including the Interconnected Transmission Owner's transmission facilities.").

[114] The facility has a 106 MW of behind-the-meter generation, with excess generation supplied to the network. *See* Greenidge Energy, 2023 10-K, available at https://ir.greenidge.com/static-files/98e642e4-cc98-4c81-8d72-142dab9bb683, at p. 8. ("Our datacenter operations in New York are powered by electricity generated directly by our power plant, which is referred to as "behind-the-meter" power as it is not subject to transmission and distribution charges from local utilities. As of December 31, 2023, our owned and customer hosted miners at the New York Facility had the capacity to consume approximately 60 MW of electricity. We have approval from NYISO to utilize 64 MW of electricity behind-the-meter.").

[115] In some cases, terminology can be confusing. For example, CAISO assesses transmission charges based on "gross load," although, within the CAISO OATT, gross load is synonymous with "metered load" after accounting for behind-the-meter supply. Also, CAISO and ISO-NE split network service charges into regional and local components. For both ISOs, regional network service charges are assessed on the basis of metered load, whereas local network service charges are determined according to the tariffs of individual transmission owners into which the load interconnects. *See* **Appendix A**.

Note also that in MISO and SPP, the ability to net is limited by the ISOs to only load that is entirely served by behind-the-meter generation and thus not designated as network load. *See* **Appendix A**.

generation desires to sell all or part of the output of its generation into the PJM market, it may qualify as an Energy Resource or a Capacity Resource and sell energy into the PJM markets.[116]

The use of netting, with charges reflecting either actual withdrawals or actual excess generation, generally applies not only for transmission charges but also for many ancillary service charges. Some ancillary services, particularly operating reserves and regulation/frequency response, are co-optimized with energy and as such, are typically assessed based on the actual amount of energy purchased in the market and withdrawn from the network.[117] Cost recovery for other ancillary services, such as reactive power/voltage support, black start, and administrative and scheduling services, may be achieved by allocating total payments to resources across customers based on either their actual energy withdrawals on an hourly basis or during certain peak load periods.[118] As with transmission, these allocations typically reflect actual withdrawals, not gross loads, when loads and generation are co-located. Recent work has demonstrated that all transmission and ancillary services charges in PJM are based on actual withdrawals.[119]

The implications of netting for co-located loads depends on the nature of the co-location. When loads are fully isolated and do not withdraw energy from the network, co-located loads will not generally incur transmission or ancillary service charges. When co-located loads are not fully isolated, but potentially withdraw energy from the network, then the charges would depend on the timing and quantity of those withdrawals. For example, when ancillary services costs are allocated based on peak load, the co-located load charges would reflect whether energy withdrawals occur during peak periods and the amount of energy withdrawn during those periods.

3. *Recent Proposed Ratemaking Relative to Existing Ratemaking*

Filings in the amended Susquehanna ISA and the Exelon utility transmission rate proceedings have raised issues with respect to both whether fully-isolated co-located loads should be required to take network transmission service and, if they do take such service, whether they should be charged for such service on a gross or net basis.

---

[116] PJM Revisions to Tariff and Amended and Restated Operating Agreement, FERC Docket No. ER04-608-000, Transmittal at 4, March 1, 2004.

[117] *See, e.g.,* PJM, "Customer Guide to PJM Billing," October, 3, 2022, available at https://www.pjm.com/-/media/markets-ops/settlements/custgd.ashx, at pp. 7-10; NYISO, "Load Serving Entity (LSE) Ancillary Services Settlements," November 27, 2023, available at https://www.nyiso.com/documents/20142/3035389/Load-Serving-Entity-Ancillary-Settlements.pdf/1e839e97-b7eb-a044-e32d-378cb9aa9655, pp. 29-32, 49-52; ISO-NE, "Regulation Calculation Summary," April 1, 2019, available at https://www.iso-ne.com/static-assets/documents/2017/02/regulation_calculation_summary.pdf, at p. 11; ISO-NE, "Real-Time Reserves Calculation Summary," June 1, 2018, available at https://www.iso-ne.com/static-assets/documents/2017/02/rt_reserves_calculation_summary.pdf, at p. 6.

[118] *See, e.g.,* PJM, "Customer Guide to PJM Billing," October, 3, 2022, available at https://www.pjm.com/-/media/markets-ops/settlements/custgd.ashx, at pp. 5, 7, 11; NYISO, "Load Serving Entity (LSE) Ancillary Services Settlements," November 27, 2023, available at https://www.nyiso.com/documents/20142/3035389/Load-Serving-Entity-Ancillary-Settlements.pdf/1e839e97-b7eb-a044-e32d-378cb9aa9655, pp. 5-9, 19-22, 59-62; ISO-NE, "OATT Schedule 1 Regional Network Service (RNS)," June 27, 2016, available at https://www.iso-ne.com/markets-operations/settlements/understand-bill/item-descriptions/oatt-schedule1-rns; ISO-NE, "OATT Schedule 2 Reactive Supply and Voltage Control Service (VAR) Calculation Summary," December 15, 2015, available at https://www.iso-ne.com/static-assets/documents/2015/12/oatt_schedule_2_reactive_supply_and_voltage_control_service_var.pdf, at p. 3; ISO-NE, "OATT Schedule 16 Blackstart Service Calculation Summary," January 1, 2019, available at https://www.iso-ne.com/static-assets/documents/support/tech/rpt_descriptions/calculation_summaries/blackstart_calc_sum.pdf, at p. 12.

[119] *See* Affidavit of Roy J. Shanker Ph.D., FERC Docket No. ER24-2888-000, October 2, 2024, ("Shanker Affidavit"), at ¶ 23.

In the amended Susquehanna ISA proceeding, certain interveners have argued that a fully-isolated co-located load should be required to take network transmission service and pay for certain ancillary services. Multiple arguments have been made, including the fact that the co-located loads are synchronized with the grid[120] and that they utilize certain ancillary services.[121] As described above, these claims are inconsistent with existing ratemaking for co-located loads, under which fully-isolated co-located loads would not be charged for either network transmission service or ancillary services as they would not actually withdraw any energy from the network.

Another issue is the basis for any charges for network service. The common use of netting and charges based on actual withdrawals[122] stands in contrast to the "clarifying" rates filed to the Commission by distribution utilities owned by Exelon.[123] These filings propose that co-located loads should always be required to take transmission service on a "gross load" basis.[124] This "clarification" is inconsistent with current ratemaking approaches in which charges are assessed on actual withdrawals from the system, not gross withdrawals. Further, as we discuss below, such rates are inconsistent with sound economic ratemaking principles.

4. Retail Service

Loads taking any service from the network do so through retail service, which is regulated by state commissions, not FERC. Typically, transmission service and certain ancillary services are supplied only through the local, monopoly distribution utility, which incurs charges for these services based on all loads within its service territory. Any retail supplier of electricity service must procure this bundled transmission service on behalf of its load customers from the distribution utility – that is, unlike energy procured directly through the wholesale markets, the retail supplier cannot "go around" the distribution utility and take transmission service directly from the wholesale market.[125] For example, co-located loads may need standby service to provide them with energy during periods when behind-the-meter generation is insufficient to meet on-site loads (e.g., due to lack of capacity or maintenance

---

[120] *See* Declaration of David Weaver, PE, FERC Docket No. ER24-2172, June 24, 2024, ("Weaver Declaration").

[121] *See* Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, FERC Docket No. ER24-2172-000, July 10, 2024, at p. 6.

[122] *See* **Table 2** in **Appendix A** for a summary of billing determinants for transmission service charges by RTO.

[123] *See, e.g., Atlantic City Electric Company*, FERC Docket No. ER24-2888-000, August 28, 2024; *Baltimore Gas and Electric Company*, FERC Docket No. ER24-2889-000; *Commonwealth Edison Company,* FERC Docket No. ER24-2890-000, August 28, 2024; *Delmarva Power & Light Company,* FERC Docket No. ER24-2891-000, August 28, 2024; *PECO Energy Company* FERC Docket No. ER24-2893-000, August 28, 2024; *Potomac Electric Power Company*, Docket No. ER24-2894-000, August 28, 2024.

[124] *See, e.g.,* Atlantic City Electric Company, Revisions to OATT Attachment H-1, Attachment 2 - Clean, FERC Docket No. ER24-2888-000, August 28, 2024, ("For further avoidance of doubt, the Network Customer Facilities required by Section 29.4 includes metering measuring the gross load of the Network Customer consistent with the Tariff and any state retail access program.") at p.2.

[125] The details of these arrangements vary across states, depending on industry structure and allowance for competitive retail supply in each state. *See* "An Introduction to Retail Electricity Choice," NREL, 2017, available at https://www.nrel.gov/docs/fy18osti/68993.pdf ("In the United States, there is a divide between wholesale and retail electricity. A number of states that are part of restructured wholesale markets do not have full retail access, such as Kansas, Oklahoma, and Minnesota. It is also possible for states to have retail electricity choice but not participate in a wholesale electricity market. For example, Georgia and Oregon both have retail electricity choice for large commercial and industrial consumers, but those states are not part of any restructured wholesale power market.") at p.3.

outage). This service must be obtained through retail service in which transmission service and charges reflect those offered by the distribution utility, which may differ from the charges incurred by the distribution utility.

In this paper, we do not evaluate in detail the issues associated with state-level retail ratemaking for co-located loads, including large digital loads. As with FERC-regulated wholesale markets, state-level ratemaking proceedings have addressed issues arising with co-located loads. While FERC-regulated ratemaking for co-located loads is relatively uniform, this is not the case for state-level regulation, particularly for rates involving limited use of the network, such as standby service. Consistent with the ratemaking principles we discuss below, efficient rates for such standby and related service should reflect cost causation and marginal costs of use.

In many cases, however, the standby rates charged by the distribution utility under approved tariffs may not reflect a pass-through of the costs caused by the co-located loads receiving such service. Such concerns have been raised in the past by co-located loads.[126] Thus, the option to fully isolate provides large loads with an alternative to the monopoly distribution company's service, which may be costly depending on the rates charged for standby service. Requiring that fully-isolated co-located loads take network transmission service would, in effect, mandate that they take monopoly distribution service, which may not be available at reasonable, efficient rates.

B. Current Ratemaking for Co-Located Loads Reflects Sound Ratemaking Principles

Appropriate ratemaking for transmission service and ancillary services should reflect the same set of considerations relevant for all utility ratemaking. The most common and well-recognized set of principles are the Bonbright principles, which center on economic efficiency, fairness, simplicity, and transparency.[127] FERC has issued ratemaking principles in its Transmission Pricing Policy Statement that follow these principles, reflecting five specific considerations: economic efficiency, the need to meet the utility's revenue requirement, fairness,[128] practicality and comparability.[129]

Below, we focus on economic efficiency as the primary driver of appropriate ratemaking for co-located loads from an economic standpoint. Although fairness criteria are relevant, particularly given the need for transmission and generation owners to recover their costs of supplying electricity services to loads, objective criteria for deviating from the cost causation principles that we describe below are not obvious. Arguments in favor of co-located loads paying for transmission (and ancillary services) often invoke the notion of fairness, requiring that all loads "should"

---

[126] *See, e.g.,* "Resolution on Standby Rates for Partial Requirements Customers," National Association of Regulatory Utility Commissioners, February 13, 2019, available at https://pubs.naruc.org/pub/AE6661DB-FCC0-663C-B336-2BAFA94A296D, at p.1; "Appendix J. Cogeneration and Distributed Generation," Fifth Northwest Electric Power and Conservation Plan," Northwest Power and Conservation Council, May 1, 2005, available at https://www.nwcouncil.org/reports/fifth-northwest-electric-power-and-conservation-plan-0/, at p. J-34.

[127] Bonbright, J. C., *Principles of Public Utility Rates*, Columbia University Press, 1961, at p. 291.

[128] Fairness is relevant to the relationship between the regulated utility and customers, and to the relationship between customers. The relationship between the regulated utility and customers reflects a tension between the regulated utility's need to recover its costs and earn a sufficient return to attract capital, and efficient prices, which may over- or under-recover the utility's costs of service.

[129] Pricing policy for transmission services provided under the Federal Power Act. *See* 18 C.F.R. § 2.22, November 3, 1994, available at https://www.ecfr.gov/current/title-18/chapter-I/subchapter-A/part-2/subject-group-ECFR917d5691f943381/section-2.22.

pay their "fair" portion of network costs.[130] Some arguments invoke the fact that even loads that are fully isolated are synchronized with the network and are therefore, in some sense, using and taking service from the network.[131] Yet, fair rates should not charge customers for services that are not used. For fully-isolated co-located loads that do not withdraw energy (or capacity) from the network, charging for network transmission service would be contrary to the fairness principle, as it would require some customers to bear costs for a service that they are not using. This conclusion derives from the common understanding of the purpose of network transmission service being the delivery of energy from generators that are distant to loads and FERC's existing regulation of transmission service and rates.

Based on the principle of economic efficiency, it is widely recognized that efficient rate design should reflect cost causation such that prices are set equal to marginal costs. For example, FERC has stated: "We favor marginal cost prices in order to promote efficient decision-making by both transmission owners and users."[132] Economic analysis shows that rates provide efficient incentives when each customer's rates are set at the marginal cost imposed by their use of the associated utility service.[133] When rates are set based on marginal costs, those taking utility service face a rate that reflects the costs they impose, at the margin, on the network. By aligning rates and marginal costs, the rates create incentives for customers to use the network efficiently, thus avoiding increased use when the cost of use exceeds the benefit of use.

In principle, the marginal cost of serving new loads can reflect several potential components: the one-time cost of interconnecting new loads, and the ongoing costs of using the network to deliver energy from generation to loads and to supply ancillary services used by loads.

Below, we evaluate cost causation for co-located loads, particularly fully-isolated co-located loads. We show that it is efficient and consistent with cost causation to not require that fully-isolated co-located loads take transmission service. We also discuss efficient rates for ancillary services, and address other issues raised regarding co-located loads, including whether co-located loads should be required to pay for non-bypassable charges used to pay for state policy programs and address concerns that co-location results in shifting costs onto other consumers.

1. Interconnection

The cost of interconnecting a new load to its source of supply, whether that be the network or a particular resource, includes the costs of new equipment needed to connect the load, such as transmission lines and substations. Incremental costs can also include the costs of upgrades to the network needed to maintain reliable system operations, including transmission security, reactive power, and voltage control.

---

[130] *See, e.g.,* Duane and Clark I, at pp. 3, 4.

[131] *See, e.g.*, Reed and Powers Declaration, at pp. 5, 10.

[132] 18 CFR Part 2, *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act*, FERC Docket No. RM93-19-000; *Policy Statement*, FERC Docket No. RM93-19-000, October 26, 1994.

[133] Kahn, A., "Marginal Cost Pricing" and "Rate-Making in the Presence of Competition," in *The Economics of Regulation: Principles and Institutions*, 2nd Edition, MIT Press, 1988, pp. 63-122.

Consistent with cost causation, new large loads should bear the costs associated with interconnecting to the system, as they are directly responsible for these costs. In practice, however, the fraction of new costs borne by new large loads may vary across utilities. In some cases, that fraction is small. For example, when interconnecting new large load customers in ComEd's service territory, the new customers incurred only 8.2% of interconnection costs.[134] As result, ComEd's existing customers, who bear a large fraction (91.8%) of these costs, in effect "cross-subsidize" the costs of these new customers.

Similarly, with co-located loads, cost causation indicates that the co-located entities should bear the interconnection costs. Ratemaking for a current example of a fully-isolated co-located load, the amended Susquehanna ISA, is aligned with this outcome. The co-located entities will bear the costs of all interconnecting facilities and any upgrades needed to maintain reliability under the new interconnection.[135]

2. Network Use

The second component reflects how a load's use of the system affects network costs. In particular, when new loads use the network for the delivery of energy and capacity, these loads may require that the transmission system be expanded to enable reliable delivery of network supplies. This new infrastructure is realized through a combination of transmission upgrades that are required when new generation interconnects to the transmission system, as well as new investment that is identified and approved through regular transmission planning.

At the margin, the need for new network infrastructure is the result of use of the network infrastructure. Loads connected directly to the network rely on the network and incremental increases in load cause, at the margin, the need for increased infrastructure to expand the network's capacity to serve that new load. While in practice, the actual incremental investment needed to serve new load on the network depends on the new load's location in the network (and associated load flows, existing transmission constraints, etc.), on average, all new loads require incremental (long-run) increases in transmission. Moreover, the need for new transmission infrastructure generally depends on loads' use of the system during the *periods of peak demand* for transmission, which are typically periods when peak coincident loads are largest. Given this, efficient rates for transmission service should reflect energy withdrawals at system peaks, which is consistent with most RTO transmission ratemaking.

For co-located loads, the marginal cost they impose on the system reflects the actual use of network transmission service for delivery of energy (and capacity). When co-located loads are fully isolated, they do not rely on the network for delivery of energy and thus have no marginal impact on the need for network transmission. Accordingly, such co-located loads should not be charged for transmission service, as they create no marginal cost for transmission service. When co-located loads are not fully isolated, their impact on the network depends

---

[134] This reflects the ratio of average requesting customer costs incurred ($981,392) to average total costs ($11,899,297). *See* ComEd Response to Constellation.

[135] Susquehanna ISA, Attachment A, Section 10.1 and Schedule F, Part B. Co-located load proposals require PJM to study if transmission system upgrades are necessary to accommodate reliably a proposed co-located load. *See* PJM Manual 14C, Interconnection Facilities, and Network Upgrade Construction, Section 1.9, available at https://www.pjm.com/-/media/documents/manuals/m14c.ashx, at p. 22; PJM Manual 14G, Generation Interconnection Requests, Section 4.5.1, available at https://www.pjm.com/-/media/documents/manuals/m14g.ashx, at p. 35.

on their actual withdrawals from the network at the periods of peak demand for transmission. Network transmission service charges across RTO/ISOs already reflect this.

In evaluating the marginal cost of co-located loads on network transmission infrastructure, costs will reflect use of the system to deliver energy and capacity, rather than other grid services. At the margin, the use of ancillary services does not contribute to the need for new transmission infrastructure. The grid needed to support ancillary services is substantially smaller than the grid needed to deliver energy (and capacity) from loads and generation that are separated geographically on the network. Thus, the need for ancillary services does not drive new transmission investment, but rather the need for a system able to deliver energy to meet peak coincident loads. Given the debate about whether co-located loads use the network for ancillary services, this has an important implication: from the standpoint of cost causation, the use of ancillary services has no bearing on the costs associated with use of network transmission service.

Some have speculated that co-located loads will shift network transmission burdens to other customers if the reduction in network supply from the co-located loads, in turn, causes the need for "new transmission to deliver replacement generation."[136] This argument is speculative and problematic for multiple reasons:

- *First*, this argument presumes that the "replacement capacity" will necessarily need new transmission capacity, which need not be the case. When a load co-locates at a generation facility, this reduces the generation facility's need for network services to deliver energy (and capacity) to customers. That is, the co-location "frees up" transmission capacity on the network. Thus, the net impact on transmission costs will depend on the "amount" of freed-up transmission capability compared to the "amount" needed by the "replacement capacity," which could be positive or negative. That is, if the replacement capacity needs less transmission than is freed up, co-location could lower transmission costs. Even those who raise this concern, such as Vincent Duane and Tony Clark ("Duane and Clark") in a whitepaper (supported by Exelon), acknowledge these tradeoffs and recognize that "reduced nuclear grid injections could free up space else [*sic*] on the high voltage network."[137]
- *Second,* measuring any alleged impact would be an entirely speculative exercise for multiple reasons. The replacement capacity could occur well after the load co-locates. Further, it would be uncertain which of many potential new resource interconnections is the resource "replacing" the reduced supply. Moreover, such analysis should account for the potential incentives to utilize the freed-up transmission capability given the reduction in interconnection costs that may occur for resources utilizing that capability.
- *Third*, the alleged effect is entirely an indirect consequence of co-location. That is, the impact of the co-located load is not due to the direct impact of co-located load and generation, but due to a potential

---

[136] Duane and Clark II, at p. 4, ("This being the case, one can reasonably expect that removing chunks of this output from the grid will effect a major change in grid topology, creating the need for (i) transmission upgrades to offset grid services previously provided by the plant and relied on by the system operator (ii) new transmission to deliver replacement generation to serve customers that have relied on the departing nuclear capacity for many years.").

[137] Duane and Clark II, at p. 5, ("NEI is correct when it says reduced nuclear grid injections could free up space else on the high voltage network, thereby enabling development of the new POIs to interconnections new generation with no or lower network upgrade responsibility.")

indirect response to that action. We are not aware of any real precedent for charging customers for such an indirect effect.

Current FERC ratemaking with respect to co-located loads, in which loads are charged based on their actual withdrawals from the system, is in line with this efficient, marginal cost pricing. Prior Commission decisions reflect this logic. For example:

> The Commission finds that . . . PJM's proposed market rules [for behind the meter generation and total netting] are just and reasonable and will encourage qualifying entities with behind the meter generation to reduce their use of the PJM transmission system . . . PJM's total netting approach is consistent with our [prior] decision [where] *the Commission specifically found that "charges for the use of PJM's transmission system should be allocated to network customers based on a network customer's actual use of PJM's system, consistent with the principle of cost causation."*[138]

Thus, the Commission is explicit that the common netting approach reflects the ratemaking principle of cost causation. Similarly, PJM echoes this logic when arguing for its netting approach:

> In the same vein, the netting approach developed by PJM and its stakeholders reduces the cost to those market participants that rely to a lesser degree on the PJM integrated transmission system to serve load because they serve loads that utilize behind the meter generation. As a result, entities that serve loads with behind the meter generation are allocated a fairer share of the costs associated with the operation of the PJM integrated transmission system, including the costs for energy, capacity, ancillary services and administrative fees.[139]

3. Ancillary Services

Along with transmission services, ancillary services are supplied over the network, typically to maintain reliable system operations (e.g., operating reserves) and ensure consistent power supply quality to loads (e.g., voltage support). As with transmission service, rates for ancillary services should reflect cost causation to ensure efficient use of ancillary services. Thus, if the load is using the ancillary service, an efficient rate for service should reflect cost causation and be set at the marginal costs of use. To the extent that the marginal cost of use is zero for all users (in the short- and long-run), the rate must then be set to ensure revenue recovery to compensate resources for the provision of the service.

With respect to ancillary services, various opinions have been made about whether certain services are being "used" by co-located load, particularly when fully isolated.[140] Given the nature of ancillary services, this becomes a technical issue, with arguments varying across services and potentially depending on the particular equipment and

---

[138] *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,113, 2004, at pp. 27-28 (citing *Occidental Chemical Corp. v. PJM Interconnection, L.L.C.*, 102 FERC ¶ 61,275, 2003 (emphasis added)).

[139] PJM Revisions to Tariff and Amended and Restated Operating Agreement, FERC Docket No. ER04-608-000, Transmittal at 7, March 1, 2004.

[140] *See, e.g.,* Weaver Declaration, at pp. 3, 9-10; Affidavit of Steven R. Herling, FERC Docket No. ER24-2888-000, et al, October 2, 2024.

configuration at the co-location facility, such as auxiliary generators, capacitors or other devices that provide voltage support, and switches to detach load from the network, if fully isolated.

In general, as we describe above, co-located loads do not impose any immediate, incremental need for ancillary services, including operating reserves, regulation/frequency response, and reactive power/voltage support.[141] That is, as co-located loads increase, RTO/ISOs (and transmission companies) typically do not adjust the ancillary service requirements that determine the amount of service to procure from resources. That said, in the long run, there is a relationship between some ancillary service requirements and system size (e.g., network load requirements). As a result, consistent with this relationship, costs are allocated based on metrics reflecting usage (e.g., peak load, load ratio share) for some ancillary services, particularly when not procured through a market mechanism.

To the extent that there is a relationship between system use and ancillary service requirements, rates reflecting actual withdrawals are consistent with efficient rates. Given this, rates for many ancillary services reflect actual withdrawals. From this vantage point, the rates charged to co-located loads for ancillary services should reflect their system use. For fully-isolated co-located loads, this implies no costs, as power is not withdrawn from the system; whereas for other co-located loads, this would depend on the amount (and potentially the timing) of actual energy withdrawals.

We do not evaluate each ancillary service with respect to these factors and criteria, but make several observations:

- **Load following**. Some have argued that co-located loads need "load following." [142] However, load following is not an ancillary service and thus there is no revenue to recover.[143] Moreover, were load following to be a service, a plant's "use" of the service would not impose incremental (marginal) costs on the transmission system, as the system required to supply load following would be smaller than the system required to deliver energy from network resources to network loads. Thus, as there is no revenue to recover (from payment of ancillary service compensation to resources) and as there is no marginal cost, there should be no charge.
- **Operating Reserves.** Co-located load (whether or not fully isolated from the grid) does not require or use grid-supplied online or offline contingency reserves if the facility has backup service provided by the co-located generators or batteries. As with other ancillary services, compensation to co-located generators should appropriately account for the provision of service to co-located loads so that generation is not compensated both for energy supplied to the co-located load and to the network.

[141] Co-located loads can be expected to bear the costs of any reactive power requirements that are not otherwise met by the co-located generation supply resource(s).

[142] For example, Weaver Declaration, at pp. 7.

[143] Load following simply refers to system operator directed changes in resource energy output to account for diurnal demand changes. Notably load following is not energy imbalance service, which is a FERC-defined ancillary service that accounts for the difference between scheduled and actual power system energy deliveries (often provided by RTO/ISO real-time energy market transactions).

- **Black start**. Many data centers have on-site, behind-the-meter backup generators that are able to supply black start service.[144] Even without such backup generators, the amount of black start capability needed to restart a generator is the same whether the generator supplies energy to the grid or to co-located load.
- **Voltage support**. Co-located generation including nuclear resources can provide reactive power voltage support. Compensation to co-located generators should appropriately account for the provision of service to co-located loads so that generation is not compensated both by the co-located load and through the network.

Thus, fully isolated co-located loads do not generally affect the existing system-wide cost being borne by existing customers.[145]

4. Non-Bypassable Charges

Another issue raised by some commenters relates to state governments' use of utility rates as a vehicle to fund government programs. In particular, some argue that co-located loads that do not take distribution or transmission service may not pay system benefits charges that are used to fund certain policy measures. For example, Duane and Clark argue that "colocated customers should pick up their share of non-bypassable charges to fund sustainability, conservation, energy justice and similar programs."[146] Similarly, John Reed and Danielle Powers ("Reed and Powers") argue in an opinion sponsored by Exelon and AEP in the amended Susquehanna ISA docket that co-located load at Susquehanna is avoiding the costs associated with PPL Electric Utilities' ("PPL's") riders for energy conservation, smart meter, and energy efficiency programs, among others.[147]

Neither Duane and Clark nor Reed and Powers provide a rationale for why customers should be required to take a particular type of service simply because legislatures have decided to fund certain government programs through charges assessed on the use of that service. Rather than modify the approach used to fund these programs, commenters seem to suggest that all loads should be required to use a certain service, in lieu of other bi-lateral arrangements, simply to increase funding for the programs. There is no basis for this assertion, and such a requirement is obviously problematic, as it strips customers of their ability to freely choose what types of services to take.

5. Claimed "Cost Shifts"

Recent debates about rates for co-located loads have been accompanied by claims that there are "cost shifts" when fully-isolated co-located loads do not pay for network transmission service. For example, Reed and Powers

[144] Microsoft Director of Energy Strategy Brian Janous stated that "Microsoft always builds a megawatt of on-site backup generation for every megawatt of grid-supplied electricity consumed at its data centers." *See* "How Microsoft and a Wyoming utility designed a data center tariff that works for everyone," *Utility Dive*, December 20, 2016, available at https://www.utilitydive.com/news/how-microsoft-and-a-wyoming-utility-designed-a-data-center-tariff-that-work/430807/.

[145] For a more in-depth review of the provision and cost allocation of these services *see* Shanker Affidavit, at pp. 18-34.

[146] Duane and Clark II, at p. 9.

[147] For PPL, these costs amount to only 2 percent of the total lost revenues Reed and Power calculate. *See* Reed and Powers Declaration, Attachment 1. *See also* PPL General Tariff, Act 129 Compliance Rider – Phase 4, available at https://www.pplelectric.com/-/media/PPLElectric/At-Your-Service/Docs/Current-Electric-Tariff/act129-compli-rider-phase4-06012023.ashx.

concluded that the amended Susquehanna ISA would lead to a "cost shift" of $58 million to $140 million annually.[148] Their estimate was based on the lost revenues that would have been collected by the utility, PPL, if the co-located load had instead located directly on PPL's system. It is not based on the incremental cost to PPL from the co-located loads. Most (98%) of these claimed lost revenues come from transmission service charges under the assumption that the co-located load should pay the rates charged to large grid-supplied load customers for taking full service directly from the transmission network.[149] However, the Susquehanna co-located load is fully-isolated and designed to never withdraw energy from the network and thus would lead to no incremental costs to PPL. Similarly, Duane and Clark allege that co-location shifts the costs of maintaining system reliability onto other consumers, estimating that the "cost shift" in PJM is on the order of $0.05 per kWh.[150]

As we show above, consistent with FERC-approved definitions of network transmission service and the assessment of charges for network transmission service for behind-the-meter loads, a fully-isolated co-located load does not take network transmission service. Neither Reed and Powers nor Duane and Clark offer any meaningful arguments in support of the assumption that the co-located load should bear the cost of network transmission service for *all* behind-the-meter load, despite the full isolation from the network. They also do not offer any reference to existing FERC rates or precedent in reaching their conclusions. Instead, they assert that any co-located load that is synchronized to the transmission grid should be required to pay for grid services even if they are not using the services.[151]

In other words, claims that there are "cost shifts" from fully-isolated co-located loads do not account for the actual configuration of the proposed co-located loads and are not supported by ratemaking principles or precedent. Instead, as we have shown above, it is economically efficient, consistent with cost causation principles, and consistent with FERC's treatment of other co-location arrangements, for fully-isolated co-located loads to not take transmission service or ancillary services as they do not use these services.

---

[148] Reed and Powers Declaration, at ¶ 11.

[149] Reed and Powers Declaration, at ¶ 16.

[150] Duane and Clark I, at pp. 3, 4.

[151] In a Supplemental Declaration, Reed and Powers reiterated their reasoning that since the Susquehanna nuclear generation unit and co-located load are synchronized to the grid, this means that there should be transmission services charges, particularly if there is an inadvertent withdrawal from the grid (which presumably could result in transmission service charges). *See* Supplemental Declaration of John J. Reed and Danielle S. Powers, FERC Docket No. ER24-272, October 15, 2024 at ¶¶ 10-14.

VI. Appendix A

Table 1: Definitions of Network Transmission Service by RTO/ISO

	RTO/ISO	Definition of Network Transmission Service
[A]	CAISO	**26. Transmission Rates and Charges** 26.1 Access Charge: (a) In General. All Market Participants **withdrawing Energy** from the CAISO Controlled Grid shall pay Access Charges in accordance with this Section 26.1 and Appendix F, Schedule 3... The Access Charge shall comprise two components, which together shall be designed to recover each participating TO's or Approved Project Sponsor's Transmission Revenue Requirement...
[B]	ISO-NE	**Section II.11 Nature of Regional Network Service:** Regional Network Service is the service over the [Pool Transmission Facility] PTF pursuant to Part II.B of this OATT which is provided by the ISO to Network Customers to serve their loads. It includes transmission service over the PTF for the delivery to a Network Customer of its **energy and capacity** in Network Resources and delivery to or by Network Customers of energy and capacity in Market transactions.
[C]	MISO	**28.3 Network Integration Transmission Service:** The Transmission Provider and, as applicable, ITC will provide Firm Transmission Service over the Transmission System to the Network Customer for the **delivery of Capacity and Energy** from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Owner(s') and ITC Participant(s') use of the Transmission System to reliably serve Native Load Customers.
[D]	NYISO	**4.1.3 Network Integration Transmission Service:** The ISO will provide Firm Transmission Service over the NYS Transmission System to the Network Customer for the **delivery of Energy** from its designated Network Resources to serve its Network Loads on a basis that is comparable to the Transmission Owner's use of the NYS Transmission System to reliably serve its Native Load Customers.
[E]	PJM	**28.3 Network Integration Transmission Service:** The Transmission Provider will provide firm transmission service over the Transmission System to the Network Customer for the **delivery of capacity and energy** from its designated Network Resources to service its Network Loads on a basis that is comparable to each Transmission Owner's use of the Transmission System to reliably serve its Native Load Customers.
[F]	SPP	**28.3 Network Integration Transmission Service:** The Transmission Provider will provide firm transmission service over the Transmission System to the Network Customer for the **delivery of capacity and energy** from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Owner(s') use of the Transmission System to reliably serve Native Load Customers.

Sources:
[A] *See* CAISO OATT, Section 26, available at https://www.caiso.com/documents/conformed-tariff-as-of-aug-1-2024.pdf. *See also* CAISO, "How Transmission Cost Recovery Through the Transmission Access Charge Works Today," April 12, 2017, available at https://www.caiso.com/Documents/BackgroundWhitePaper-ReviewTransmissionAccessChargeStructure.pdf, at p.13 ("The original structure [of the Transmission Access Charge] based on a volumetric $/MWh rate was established to reflect the fact that the ISO market, through which use of the transmission system is allocated and scheduled, is an energy market, not a capacity market. In other words, use of the ISO controlled grid is scheduled based on the hourly MWh energy volumes for which market participants need transmission service, and the current volumetric TAC and WAC rate structure aligns with this market structure.").
[B] ISO-NE OATT, Section II, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf.
[C] MISO OATT, Section 28, available at https://misodocs.azureedge.net/miso12-legalcontent/TariffAsFiledVersion.pdf.
[D] NYISO OATT, Section 4, available at https://nyisoviewer.etariff.biz/viewerdoclibrary/mastertariffs/9FullTariffNYISOOATT.pdf.
[E] PJM OATT, Section 28, available at https://pjm.com/directory/merged-tariffs/oatt.pdf.
[F] SPP OATT, Section 28, available at https://spp.etariff.biz:8443/ViewerDocLibrary/MasterTariffs//5FullTariff.pdf.

Table 2: Billing Determinants for Network Transmission Service Charges by RTO/ISO

	RTO/ISO[1]	Name of Network Service	Services Delivered	Billing Determinant	Netting for BTMG[5]
[A]	**CAISO**	Transmission Access	Energy	Actual Energy Withdrawals[2]	Yes
[B]	**ISO-NE**	Regional Network Service	Energy and Capacity	Monthly Hourly Peak[3]	Yes
[C]	**MISO**	Network Integration Transmission Service	Energy and Capacity	Monthly Hourly Peak[3]	Limited[6]
[D]	**NYISO**	Network Integration Transmission Service	Energy	Actual Energy Withdrawals[3]	Yes
[E]	**PJM**	Network Integration Transmission Service	Energy and Capacity	Zonal Annual Peak[4]	Yes
[F]	**SPP**	Network Integration Transmission Service	Energy and Capacity	Monthly Hourly Peak[3]	Limited[6]

Notes:
[1] CAISO and ISO-NE also have Local Charges based on zone-specific rates.
[2] "Actual Energy Withdrawals" refers to practice of charging network customers based on their metered load in MWh.
[3] "Monthly Hourly Peak" refers to the practice of charging network customers based upon their monthly network load ratio share of transmission service, which is based upon their hourly load coincident with the monthly peak for each network zone or customer area.
[4] "Zonal Annual Peak" refers to when PJM charges a daily demand charge for network transmission service (aggregated into a monthly charge) based on the network customer's daily network service peak load contribution (including losses), coincident with the zonal peak for the 12 months ending October 31 of the preceding year.
[5] "Netting for BTMG" refers to the practice of billing Behind-the-Meter Generation facilities ("BTMG") for transmission network service based on their net (actual) energy withdrawals from the grid.
[6] MISO and SPP only allow netting for loads that are entirely served by behind-the-meter generation. *See* SPP, "Network Load Reporting," March 28, 2018, available at https://www.spp.org/documents/56715/network%20load%20reporting_mopc%20outreach_final.pdf, at pp. 12, 19; MISO OATT, Section 1.N, available at https://misodocs.azureedge.net/miso12-legalcontent/TariffAsFiledVersion.pdf.

Sources:
[A] CAISO OATT, Section 26, available at https://www.caiso.com/documents/conformed-tariff-as-of-aug-1-2024.pdf.
[B] ISO-NE OATT, Section II, available at https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf.
[C] MISO OATT, Section 34, available at https://misodocs.azureedge.net/miso12-legalcontent/TariffAsFiledVersion.pdf; MISO, Business Practices Manual, Transmission Settlements, Section 3, available at https://cdn.misoenergy.org/BPM-012%20Transmission%20Settlements49565.zip.
[D] NYISO OATT, Section 2, available at https://nyisoviewer.etariff.biz/viewerdoclibrary/mastertariffs/9FullTariffNYISOOATT.pdf.
[E] PJM OATT, Section 34, available at https://pjm.com/directory/merged-tariffs/oatt.pdf.
[F] SPP OATT, Section 34, available at https://spp.etariff.biz:8443/ViewerDocLibrary/MasterTariffs//5FullTariff.pdf.