



ENVIRONMENTAL LAW & POLICY CENTER

June 12, 2025

Via E-File

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-21859

Dear Ms. Felice:

Attached for paperless electronic filing, please find the Direct Testimony and Exhibits of Saad Siddique on behalf of The Ecology Center, The Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar (collectively the “Clean Energy Organizations” or “CEO”). Also attached is the proof of service.

Sincerely,

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cc: Service List, Case No. U-21859

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**STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION**

In the Matter of the Application of	)	
Consumers Energy Company for Ex Parte	)	Case No. U-21859
Approval of Certain Amendments to Rate	)	
GPD.	)	

DIRECT TESTIMONY OF

SAAD SIDDIQUE

ON BEHALF OF

**THE ECOLOGY CENTER, ENVIRONMENTAL LAW & POLICY CENTER, UNION
OF CONCERNED SCIENTISTS, AND VOTE SOLAR**

June 12, 2025

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1 **I. Introduction and Summary**

2 **Q: Please state your name and business address.**

3 A: My name is Saad Siddique (he/him/his). My business address is 35 E. Wacker Dr., Ste.
4 1600, Chicago, Illinois 60601.

5 **Q: By whom are you employed and in what capacity?**

6 A: I am employed by the Environmental Law & Policy Center (“ELPC”) as an economist &
7 energy analyst.

8 **Q: On whose behalf are you submitting this direct testimony?**

9 A: I am submitting testimony on behalf of The Ecology Center, ELPC, Union of Concerned
10 Scientists, and Vote Solar, collectively referred to as the “Clean Energy Organizations” or
11 “CEO.”

12 **Q: Please summarize your qualifications, experience, and education.**

13 A: I have been employed at ELPC since November 2023. As an economist & energy analyst,
14 I provide research, engineering and economic analyses, and data analysis in utility rate
15 cases, grid and resource planning proceedings, and energy policy issues at ELPC.
16 Previously, I was a Senior Energy Systems Analyst at GTI Energy from 2022-2023, where
17 I led a long-term strategy planning and modeling project for natural gas, hydrogen, and
18 carbon capture, utilization and sequestration infrastructures in the lower 48 states of the
19 US to reach economy-wide net-zero CO₂ goals by 2050. I also led a project that conducted
20 a meta-analysis of multiple decarbonization studies that modeled and analyzed
21 technological, economic, and policy pathways to economy-wide net-zero emissions by
22 2050 for the U.S. Prior to joining GTI Energy, I worked as a Sustainability Analyst at
23 Stanford University from 2021-2022. I hold a Master of Science in Energy and Earth

Resources from The University of Texas at Austin (2020), where I wrote a thesis on investment and strategic decision-making for gas pipeline infrastructure projects under uncertainty and under risks of cost-and-time overruns. In 2018, I received a certification in Economics, Financial Accounting and Business Analytics from Harvard Business School Online. I graduated with a Bachelor of Engineering in Mechanical Engineering (2015) from Visvesvaraya Technological University in India. My resume is attached as Ex. CEO-1.

Q: Have you testified before the Michigan Public Service Commission previously?

A: Yes. I previously testified in U-21291, DTE Gas Company's rate case.

Q: Have you testified or provided comments in similar state regulatory proceedings?

A: Yes. I have provided testimony in ongoing rate cases before the Illinois Commerce Commission:

- 25-0055 Nicor Gas Rate Case
- 25-0084 Ameren Illinois Company Gas Rate Case

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

- Exhibit CEO-1: Resume of Saad Siddique
- Exhibit CEO-2: Consumers' Discovery Response DCC-CE-0005
- Exhibit CEO-3: Consumers' Discovery Response DCC-CE-0052
- Exhibit CEO-4: Consumers' Discovery Response MNSC-CE-0081
- Exhibit CEO-5: Consumers' Discovery Response CEO-CE-0115
- Exhibit CEO-6: Eliza Martin & Ari Peskoe, *Extracting Profits from the Public: How Utility Rate Payers Are Paying for Big Tech's Power*, Harvard Environmental & Energy Law Program (Mar. 2025)

- 1 • Exhibit CEO-7: MISO Generator Interconnection Queue Update (Dec. 10, 2024)
- 2 • Exhibit CEO-8: Tyler H. Norris et al., *Rethinking Load Growth: Assessing the Potential*
- 3 *for Integration of Large Flexible Loads in the US Power Systems*, Duke Nicholas
- 4 Institute for Energy, Environment, & Sustainability (2025)
- 5 • Exhibit CEO-9: Consumers Discovery Response CEO-CE-0114(f)

6 **Q: What is the purpose of your testimony?**

7 A: The purpose of my testimony is to review and analyze Consumers Energy Company's
8 ("Consumers" or the "Company") proposed changes to Rate GPD, as well as the
9 Company's plan to meet its state-mandated renewable energy obligations in light of
10 projected significant increases in new data center load. Ultimately, I propose several
11 modifications to the Company's proposed tariff terms and conditions related to clean
12 energy, which will help ensure that the Company continues on its current trajectory towards
13 decarbonization and compliance with its clean and renewable energy obligations. I
14 designed my set of recommendations to promote and encourage prospective data center
15 customers to utilize several pathways for clean energy development as part of their
16 application for service under Rate GPD, including front-of-the-meter resources, behind-
17 the-meter resources and demand flexibility.

1 **II. Background**

2 **A. *Consumers’ Proposed Terms and Conditions***

3 **Q: What is Consumers proposing in this case?**

4 A: Consumers proposes a set of changes to Rate GPD “that are necessary to serve new data
5 center load while protecting other customers.”¹ Specifically, the Company proposes seven
6 additional terms and conditions for prospective data center customers including: (1) a 15-
7 year minimum contract term; (2) a minimum billing demand requirement; (3) a set of
8 financial security stipulations; (4) an exit fee requirement; (5) a one-time reduction in
9 contract capacity at the Company’s discretion; (6) a provision allowing suspension or
10 contract amendment if the customer uses 1,000 kW or more above contracted capacity; and
11 (7) an upfront administrative fee for project proposal.²

12 **Q: What customers would these proposed terms and conditions apply to?**

13 A: The Company proposes that new data center customers would take service under Rate GPD
14 with these terms and conditions. The Company defines a data center as “a centralized
15 facility used for management, storage, processing, and distribution of data with a load of
16 100 MW or more at a single site or on an aggregated (more than one site in the Company’s
17 service territory) basis.”³

¹ MPSC Case No. U-21859, Consumers Direct Testimony of Laura M. Connolly at 3 (filed Feb. 2, 2025), available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000ZUNZTAA5>.

² *Id.* at 5.

³ *Id.* at 4.

1 **Q: Why does the Company believe these additional terms and conditions are**
2 **necessary?**

3 A: In her testimony, Company Witness Laura Connolly describes that the Company “has seen
4 an influx in requests to serve new data center load over the last 12 months and expects this
5 trend to continue.”⁴ Witness Connolly stated that the Company has had 15 gigawatts worth
6 of inquiries for new data center load, though no timeline is indicated.⁵ In response to
7 discovery on Company’s data center “pipeline,” the Company indicated that it has engaged
8 with the Transmission Owner to evaluate 2.65 GW of large load additions by 2035.⁶
9 According to the Company, these 2.65 GW of large load additions are “based on advanced
10 discussions with economic development and data center projects that are considered to be
11 more probable prospects.”⁷

12 **B. Michigan Climate Law**

13 **Q: What amount of renewable energy and clean energy does Michigan law require by**
14 **year for Consumers Energy to provide its customers?**

15 A: Michigan law mandates distinct annual targets for renewable energy and clean energy
16 under Michigan’s 2023 climate and energy legislation (“Climate Law”).⁸ These
17 requirements apply to all electric providers, including Consumers Energy, and are
18 structured as follows:

⁴ Connolly Direct Testimony at 4.

⁵ *Id.*

⁶ Ex. CEO-2, Consumers’ Discovery Response DCC-CE-0005.

⁷ Ex. CEO-3, Consumers’ Discovery Response DCC-CE-0052.

⁸ Michigan Public Acts 229, 231, 233, 234, and 235 of 2023.

1 Renewable Energy Standard (“RES”)

2 The RES requires electric providers to source an escalating percentage of renewable energy
3 credits from qualifying generation over time. Under MCL 460.1028, the RES mandates a
4 renewable energy credit portfolio of at least the following:

- 5 • 15% from 2023 through 2029
- 6 • 50% from 2030 through 2034
- 7 • 60% from 2035 onward

8 Renewable energy sources include wind, solar, biomass, hydroelectric, and landfill gas.
9 Compliance is tracked using Renewable Energy Credits (“RECs”), where one REC equals
10 one megawatt-hour of renewable generation.

11 Clean Energy Standard (“CES”)

12 The CES defined in MCL 460.1051, expands the scope to include non-renewable carbon-
13 free sources. It requires:

- 14 • 80% clean energy from 2035 through 2039
- 15 • 100% clean energy from 2040 onward

16 Clean energy encompasses renewables plus nuclear, hydrogen, and natural gas with carbon
17 capture. Utilities may meet 20% of the 2035 target and 40% of the 2040 target with non-
18 renewable clean energy, provided they submit compliance plans via Integrated Resource
19 Plans (“IRPs”) approved by the Public Service Commission.

20 **Q: Why is Michigan’s Climate Law relevant to this data center tariff proceeding?**

21 A: Large new loads such as those covered by the GPD amendment will materially affect the
22 Company’s ability to meet its statutory renewable and clean energy obligations due to the
23 size of the potential new load and the speed at which it will be coming online. Michigan’s

1 RES and CES targets are expressed as a percentage of the Company’s overall electric load.
2 Therefore, if the Company’s overall load increases, the total amount of renewable and clean
3 energy capacity it needs to meet its obligations will increase proportionally. Significant
4 data center load growth will therefore create two separate challenges for the Company:
5 meeting increased demand to maintain resource adequacy *and* accelerating renewable
6 procurement to comply with Michigan statutory targets. This has cost and planning
7 implications for both the utility and its ratepayers.

8 ***C. Potential Data Center Load and Impact on Consumers’ Climate Law Obligations***

9 **Q: How much data center load does Consumers project/anticipate?**

10 A: Consumers stated that it has data center inquiries that total over 15 gigawatts of electric
11 load in the economic development pipeline, which is nearly double the utility’s current
12 peak load. While the pipeline of inquiries is extraordinarily large, the Company’s own
13 filings and testimony clarify a “more probable,” but still very large, forecast of 2.65 GW
14 of large load additions by 2035.⁹ For context, Consumers’ largest Rate GPD customer
15 today is only 28 MW.¹⁰

16 **Q: Has Consumers Energy calculated how much new renewable energy it will need to**
17 **meet this data center load?**

18 A: Broadly, no. The Company states that “[t]he specific amounts and resource types are still
19 unknown and will be presented in the Company’s next integrated resource plan (“IRP”)
20 filing, which is anticipated in quarter 2 of 2026.”¹¹ In a discovery response, the Company

⁹ Ex. CEO-2.

¹⁰ Connolly Direct Testimony at 9, 15-16.

¹¹ Ex. CEO-4, Consumers’ Discovery Response to MNSC-CE-0081.

1 indicates that its latest Renewable Energy Plan (“REP”), filed in Case No. U-21816,
2 includes sufficient renewables to meet an expected 1,145 MW of data center load by
3 2032.¹² This is much less than the 2.65 GW (or 2,650 MW) of “more probable” data center
4 load the Company identified in this case.

5 **Q: How much renewable energy would Michigan’s Climate Law require for**
6 **Consumers to keep pace with 2.65 GW of data center demand?**

7 **A:** To serve 2.65 GW of data center load while complying with Michigan’s Climate Law,
8 Consumers would need to procure **12 million RECs from new renewables in 2035**,
9 necessitating **4,748–5,987 MW** of equivalent wind or solar capacity in 2035.

10 I calculated these estimates using the following assumptions and inputs:

11 **1. Data Center Energy Consumption:**

12 a. **Annual Load:** $2.65 \text{ GW (2,650 MW)} \times 8,760 \text{ hours/year} \times 86.6\% \text{ (load factor)} =$
13 **20,103,324 MWh/year.**¹³

14 b. **Incremental RES Obligation in 2035:** $60\% \text{ of } 20,103,324 \text{ MWh} = 12,061,994$
15 **MWh/year** from renewables.

16 **2. Incremental Renewable Capacity Requirements:**

17 a. **Wind Energy:** Assuming a **29% capacity factor**,¹⁴ required capacity is:
18 **$12,061,994 \text{ MWh} \div (8,760 \text{ hours} \times 0.29) = 4,748 \text{ MW}$.**

19 b. **Solar Energy:** Assuming a **23% capacity factor**,¹⁵ required capacity is:
20 **$12,061,994 \text{ MWh} \div (8,760 \text{ hours} \times 0.23) = 5,987 \text{ MW}$.**

¹² Ex. CEO-5, Consumers Discovery Response CEO-CE-0115.

¹³ Consumers uses an 86.6% load factor to convert MW of Rate GPD load to MWh. See Ex. CEO-5.

¹⁴ MPSC Case No. U-21816, Consumers Direct Testimony of Kenneth D. Johnston at 23 (Filed Nov. 15, 2024), available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000MXga8AAD>.

¹⁵ *Id.*

1 This calculation is conservative because it looks only at the RECs (MWhs) needed
2 to meet Michigan’s Climate Law requirements, and not the time-matched capacity
3 requirements needed to maintain resource adequacy.

4 **Q: How does this new REC obligation compare to the Company’s current Renewable**
5 **Energy Plan?**

6 **A:** Adding 2.65 GW of data center load would leave the Company well short of its renewable
7 energy targets. According to the Company’s most recent REP, Consumers has procured a
8 renewable energy credit portfolio of 3,803,073 RECs in 2023 to satisfy its current RES
9 obligations.¹⁶ In its REC forecast in that case, Consumers stated that it plans to procure
10 24,920,424 RECs in 2035.¹⁷ This estimate includes 1.145 GW of new data center load
11 through 2035.¹⁸

12 In order to serve 2.65 GW of new data center load (per the Company’s current
13 projections in this case), Consumers would need an additional 6.85 million RECs.¹⁹ In
14 total, Consumers would need to procure 31.77 million RECs in 2035, which is more than
15 an eightfold increase from the 3.8 million RECs it has procured in 2023. This is a
16 conservative estimate because it reflects only the 2.65 GW of data center load that the
17 Company considers “more probable” based on advanced discussions, not the full 15 GW

¹⁶ MPSC Case No. U-21816, Consumers Exhibit No.: A-36 (CCO-4) REVISED (Originally filed Nov. 2024), available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000llqjGAAQ> (at PDF 28).

¹⁷ MPSC Case No. U-21816, Consumers Exhibit No.: A-34 (CCO-2) REVISED, (Originally filed Nov. 2024), available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000llqjGAAQ> (at PDF 26).

¹⁸ Ex. CEO-5.

¹⁹ **Additional MWh Attributable to Data Centers in 2035:** 2.65 GW (estimated today) – 1.145 GW (in current REP) = 1.505 GW of incremental data center load. 1.505 GW (1,505 MW) × 8,760 hours/year × 86.6% (load factor*) = 11,417,170 **MWh/year of incremental data center load**. (Consumers uses an 86.6% load factor to convert MW of peak load to MWh. See Ex. CEO-5.)

Incremental RES Obligation: 2035: 60% of 11,417,170 MWh = **6,850,302 additional RECs/year** from renewables.

1 of inquiries that Consumers Witness Connolly identified in her testimony.²⁰ If the full 15
2 GW materializes, Consumers would need to procure significantly more RECs.

3 **Q: Does the Company’s proposed amendments to its GPD tariff include any terms or**
4 **conditions to help facilitate compliance with Michigan’s renewable and clean energy**
5 **standards?**

6 A: No. The Company has argued in this docket that “the impact of data centers on other utility
7 requirements such as compliance with the renewable energy credit standard and the clean
8 energy standard” is not relevant to this proceeding.²¹

9 **Q: How do you respond to the Company’s position that RES issues are not relevant to**
10 **this proceeding?**

11 A: Without offering a legal opinion, I think that ignoring RES compliance in this docket and
12 waiting for a future proceeding would result in more costs and risks for Michigan
13 ratepayers. The very large additional REC obligations resulting from projected growth in
14 data center load will require a shift in planning strategy given both the scope and speed of
15 growth from data centers. By addressing these challenges now, the Commission can help
16 ensure that data centers play a more direct role in solving them. Importantly, enabling and
17 promoting prospective data center customers to “bring their own clean energy” through the
18 GPD tariff will broaden Consumers’ ability to procure resources in its territory in a more
19 timely way, ensuring that large loads help to drive—not derail—the state’s clean energy
20 transition.

²⁰ Connolly Direct Testimony at 4.

²¹ MPSC Case No. U-21859, Consumers’ Application for Leave to Appeal the Administrative Law Judge’s April 16, 2025 Ruling at 3 (filed Apr. 30, 2025), available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000mh5LpAAI>.

D. Implementation Challenges Posed by Potential Data Center Load

Q: What are the challenges associated with connecting large data center loads to Michigan’s electric grid?

A: Integrating 2.65 GW of new data center load (or more) onto Michigan’s grid presents multifaceted challenges due to the scale of the potential new load and the speed at which it will be coming online.

First, interconnecting 2.65 GW of new data center load will place significant strain on Michigan’s existing transmission and distribution systems, which may require substantial upgrades to maintain reliable service. This will be expensive, as the costs of key transmission infrastructure components have risen sharply in recent years. According to the International Energy Agency, “prices for cables have nearly doubled since 2019, and the price of power transformers rose by around 75%.” The IEA explains that “the combination of rising component costs, extended procurement lead times, and a significant backlog of orders is contributing to higher project expenses as well as delays.”²²

Higher prices underscore the need for careful, equitable allocation of those costs by the Commission to ensure other ratepayers are not held responsible for the costs incurred to serve new data center load. The Harvard Electricity Law Initiative found that “data center infrastructure costs are finding their way into power bills—to the benefit of utilities that earn a return on those investments.”²³ The report highlights that in Virginia, a \$23

²² International Energy Agency, *Building the Future Transmission Grid*, Executive Summary at 7; see also 26–27 (Feb. 2025), available at <https://iea.blob.core.windows.net/assets/a688d0f5-a100-447f-91a1-50b7b0d8eaa1/BuildingtheFutureTransmissionGrid.pdf>.

²³ Ex. CEO-6, Eliza Martin & Ari Peskoe, *Extracting Profits from the Public: How Utility Rate Payers Are Paying for Big Tech’s Power*, Harvard Environmental & Energy Law Program at 16 (Mar. 2025).

1 million substation built primarily for data centers was paid for through the regulated
2 transmission tariff, “half of which is ultimately assigned to residential ratepayers.”²⁴ This
3 example demonstrates that, without careful cost allocation or incentives to minimize new
4 infrastructure or upgrades, the significant expenditures necessary to serve large new loads
5 can be socialized to all ratepayers, not just those causing the demand.

6 **Q: What are the challenges associated with bringing new renewable energy generation**
7 **online to serve anticipated large data center loads?**

8 Adding 2.65 GW of data center load by 2035 while complying with Michigan’s Clean
9 Energy Law will require Consumers to procure substantial new renewable capacity beyond
10 current plans. As calculated above, Consumers must secure an *additional* 4.8-6 GWs of
11 wind and solar energy by 2035 to meet its 60% RES target—and even more if data center
12 growth continues, as witness Connolly predicts.²⁵

13 MISO’s generation interconnection backlog highlights the scale of the challenge in
14 bringing new generation—including renewables—online in the Midwest. As of November
15 2024, the queue contained 1,603 active requests totaling 309 GW, a figure that far exceeds
16 MISO’s all-time system peak load of 127 GW.²⁶ The standard interconnection process now
17 takes three to four years per cycle, even though the tariff sets a target of one year. This
18 delay stems largely from restudies triggered by late-stage project dropouts, which prevent
19 timely processing of later cycles.²⁷

²⁴ Ex. CEO-6 at 18; Jeffrey Tomich, *Utility Customers Already Subsidizing Data Center Boom – Study*, E&E News (Mar. 7, 2025, 6:32 AM), <https://www.eenews.net/articles/utility-customers-already-subsidizing-data-center-boom-study/>

²⁵ Connolly Direct Testimony at 4.

²⁶ Ex. CEO-7, MISO Generator Interconnection Queue Update at 4.

²⁷ Ex. CEO-7 at 4.

1 In addition to the interconnection backlog, the ability of Consumers to build new
2 renewable generation is constrained by other real-world limitations such as physical
3 infrastructure limits, siting barriers, and workforce limitations. As evidenced in the
4 Company’s last IRP, Consumers reasonably employs “build limits” in its IRP modeling
5 software to reflect these constraints when modeling how much renewable energy buildout
6 is anticipated per year. For example, in its last IRP, Consumers modeled a limit of **500**
7 **MW of new** solar buildout per year, reflecting constraints on siting and internal company
8 capacity.²⁸ For wind, the company imposed a MISO-wide limit of 5.5 GW per year, based
9 on historical project approvals.²⁹

10 These challenges create significant risk that data center load will come online faster
11 than Consumers can build and interconnect the renewable energy generation needed to
12 serve that load in line with the state’s RES mandate.

13 **Q: What can the Commission do to mitigate some of these challenges?**

14 **A:** Given the significant constraints on bringing new renewable energy generation online and
15 the risk of cost shifts, proactive tariff reforms in *this* docket—such as requiring data centers
16 to fund new renewable generation and prioritizing their interconnection—are essential to
17 prevent these infrastructure expenses from being socialized to Michigan ratepayers while
18 ensuring that Consumers can meet its RES obligations. These tariff reforms should (1)
19 clarify the availability of existing pathways for grid-scale renewables development (*e.g.*
20 through Consumer’s Voluntary Green Pricing (“VGP”) program); (2) encourage

²⁸ MPSC Case No. U-21090, Consumers Exhibit A-2 at 509 (filed Oct. 25, 2021), available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t000000VhP4HAAV>.

²⁹ MPSC Case No. U-21090, Consumers Direct Testimony of Sara T. Walz (redacted version) at 35 (filed June 30, 2021), available at <https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t000000Nib8YAAR>

1 prospective data customers to deploy the maximal set of behind-the-meter solutions, such
2 as on-site storage, generation, and load flexibility;^{30,31} and (3) encourage optimal siting and
3 operational behavior by potential data center customers in order to minimize capital costs
4 for infrastructure required to serve the load and minimize costs. These steps can help reduce
5 the burden on Consumers and the associated cost and risk for its ratepayers by procuring
6 the renewable energy needed to meet these significant new loads as they come online.

7 **III. Recommendations**

8 **Q: Do you agree with the Company’s plan to wait until the 2026 IRP to begin addressing**
9 **the renewable energy needs driven by data center load growth?**

10 No. The utility’s next IRP will start in 2026, and the new generation authorized in that
11 docket may not come online until many years later. Delaying action until the next IRP
12 could lead to rushed procurements, higher costs, and more risk for Consumers Energy and
13 its customers.

14 **Q: What do you recommend?**

15 A: To align Consumers’ data center load growth with Michigan’s mandates for 50%
16 renewable energy by 2030 and 60% by 2035 under PA 235, I recommend the Commission
17 (1) require potential data center customers to develop clean energy sourcing plans as part
18 of their applications for electric service, and (2) direct Consumers to prioritize new load
19 interconnection applications that include sufficient clean energy commitments. My

³⁰ Ex. CEO-8, Tyler H. Norris et al., *Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in the US Power Systems*, Duke Nicholas Institute for Energy, Environment, & Sustainability (2025).

³¹ For example, according to the study, on-site “load flexibility offers a promising near-term strategy for regulators and market participants to more quickly integrate new loads, reduce the cost of capacity expansion and enable greater focus on the highest-value investments in the electric power system.”

1 recommendations would ensure that the additional costs and risks of serving new data
2 center load and meeting Michigan’s clean energy requirements are borne primarily by the
3 customers that cause them. These costs include clean energy procurement and any
4 infrastructure investments that may be required to serve new data center load.

5 Specifically, I recommend that the Commission direct Consumers to incorporate
6 the following terms related to clean energy in its Tariff for data center customers:

- 7 • Customer Application Requirements and Clean Energy Sourcing Plans: The
8 Company’s tariff should require data center customers to file detailed clean energy
9 sourcing plans as a part of their applications for electric service. These plans should
10 describe the customer’s behind-the-meter measures (including distributed generation,
11 energy storage, and/or load flexibility capabilities) and any other clean energy
12 procurement strategies (including participation in VGP programs). This information
13 (“Clean Energy Sourcing Plan”) should be used by Consumers to evaluate how the
14 addition of the load will impact the Company’s system and its compliance with RES
15 obligations.
- 16 • Interconnection Processes and Prioritization: The Commission should direct
17 Consumers to prioritize the interconnection of data center customers that demonstrate
18 through their Clean Energy Sourcing Plans that their load would not negatively impact
19 Consumers’ compliance with its RES obligations and/or otherwise pose less of a
20 burden on the Company’s system. Load paired with behind-the-meter renewable
21 generation, energy storage, or load flexibility poses less of a burden on the Company’s
22 grid, requires less upgrades to the Company’s systems, and incurs less costs to comply
23 with the Company’s RES obligations. For these reasons, it would be appropriate for

1 the Commission to direct Consumers to prioritize load interconnection requests that
2 incorporate these behind-the-meter strategies.

- 3 • Encourage Utilization of Consumers' VGP Program: The Tariff should include a clear
4 pathway for prospective data center customers to utilize Consumers' Voluntary Large
5 Customer Renewable Energy Program (or a similar program) to access new,
6 incremental, time-matched, deliverable clean energy to help serve their new load
7 requirement. Data center customers that take steps to "bring their own clean energy"
8 through these programs will reduce the compliance costs and risks borne by other
9 Consumers customers through the Company's REP. It is therefore appropriate for the
10 Commission to direct Consumers to prioritize load interconnection requests that utilize
11 these programs as part of their Clean Energy Sourcing Plans.

- 12 • Customer Reporting and Accountability Requirements: Once a customer is receiving
13 electric service, it should be required to provide periodic updates on the status of its
14 clean energy procurement strategies to ensure that the customer is meeting the clean
15 energy commitments made in its interconnection application and Clean Energy
16 Sourcing Plan. Relatedly, the Commission should direct Consumers to include
17 information relating to its compliance with these clean energy terms in the Company's
18 proposed annual report to the Commission on data center customers.

19 **Q: Explain the Clean Energy Sourcing Plans in more detail.**

20 A: As explained above, Consumers and the Commission can and should lay the foundation
21 for its IRP and future Climate Law compliance by enabling proactive renewable energy
22 development that is funded and facilitated by the data center customers themselves. As the
23 first step in doing so, Consumers must ensure that it is provided with information necessary

1 to evaluate the impact of new data center load on its renewable energy obligations.
2 Therefore, the Commission should direct Consumers to require data center interconnection
3 applications to contain detailed information about a potential customer's behind-the-meter
4 measures (including distributed generation, energy storage, and/or load management
5 capabilities) and any other clean energy strategies (including participation in VGP
6 programs or other front-of-the-meter clean energy procurements). An applicant's Clean
7 Energy Sourcing Plan should then be used to by Consumers to evaluate the impact of a
8 potential data center customer on the Company's distribution and transmission systems and
9 RES obligations as well as to prioritize interconnection applications that cause less burden
10 or pose less risk to Consumers. Such evaluation should consider the specific location where
11 the data center seeks to interconnect, what distribution system upgrades or expansions may
12 be needed to support this customer, and how costs for these upgrades would be paid.

13 **Q: Explain why the VGP program is an appropriate fit for data center customers.**

14 A: Consumers' VGP program allows a customer to voluntarily specify a certain amount of
15 electricity purchases to be from renewable energy resources. Under the Company's VGP
16 program, non-participants do not subsidize costs associated with procuring renewable
17 energy pursuant to the program. Consumers has indicated that its existing VGP would be
18 available to new data center customers.³²

19 Importantly, allowing for data center customers to utilize the Company's VGP
20 program or a similar program aligns with these customers' public commitments to clean
21 energy and could assist customers in meeting those commitments. Many companies that
22 own and operate data centers or lease data center capacity have committed to certain targets

³² Ex. CEO-9, Consumers Discovery Response CEO-CE-0114(f).

1 of renewable energy at their facilities. For example, Meta is publicly committed to
2 matching 100 percent of its electricity use with renewable energy.³³ Microsoft is committed
3 to being carbon-negative by 2030.³⁴ And Google aims to achieve net-zero emissions across
4 all of its operations and value chain by 2030.³⁵

5 From the Company's standpoint, increased participation of new large load
6 customers in the VGP program would assist the Company in meeting its RES obligations,
7 as load subscribed to the VGP program does not count against the Company's RES
8 calculation.³⁶ VGP resources connected to Consumers' distribution system also may avoid
9 some of the challenges and bottlenecks associated with MISO's generator interconnection
10 process on the transmission network. For those reasons, the Company should incentivize
11 participation of new data center customers in its VGP program by prioritizing new load
12 interconnection applications for customers that participate in the program.

13 **Q: In summary, why is it important for the Commission to direct Consumers to include**
14 **clean energy terms in its large load tariff?**

15 **A:** The clean energy tariff provisions described above balance urgency with equity, ensuring
16 data centers fund their proportional share of clean energy investments while benefiting
17 from accelerated interconnection. By leveraging existing mechanisms, such as the
18 Company's VGP program, behind-the-meter resources and load flexibility, new data center
19 customers can help Consumers meet Michigan's Climate Law targets without shifting costs

³³ See <https://sustainability.atmeta.com/energy/>.

³⁴ See <https://www.microsoft.com/en-us/corporate-responsibility/sustainability?msocid=3d7468520c2f66e005f97e520da967af>.

³⁵ See <https://sustainability.google/operating-sustainably/net-zero-carbon/>.

³⁶ See MCL 460.1028.

1 to other ratepayers. If the Company's GPD tariff ignores these issues, it will shift the cost
2 and risk from data centers to the Company's other customers.

3 **Q: Does this conclude your testimony?**

4 **A:** Yes.

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Facilitating Equitable Energy Transitions with Systems Thinking | Economics | Engineering | Data | Modeling

PROFESSIONAL EXPERIENCE

ENVIRONMENTAL LAW & POLICY CENTER

Chicago, IL

Economist & Energy Analyst

2023 – Present

- I provide expert testimony for ELPC and partner organizations in utility rate cases and future of natural gas proceedings in front of the State Public Service/Utility Commissions.
- I perform engineering and economic evaluation, research and data analysis in grid and resource planning proceedings, drafting energy legislative bills, and energy policy issues.
- Conduct analysis on US energy markets and decarbonization programs like demand response, time-of-use rates, energy efficiency, non-pipeline and non-wire alternatives, grid enhancing technologies, hydrogen, certified gas, RNG, CCUS, offshore wind, solar and long duration storage.

GTI ENERGY

Houston, TX

Senior Energy Systems Analyst

2022 – 2023

- Principal Investigator for three projects under the Low-Carbon Resources Initiative (LCRI) with focus on hydrogen, carbon removal and sustainable fuels infrastructure networks considering Inflation Reduction Act and Justice 40.
- Actively contributed to the decarbonization pathways report of the LCRI US Net-Zero by 2050 program.
- Performed TEAs and LCAs mainly to create a standard industry-wide protocol for measuring emissions for various hydrogen production methods and technologies. Enhanced GTI Energy's role in energy systems modeling (ESM).

STANFORD UNIVERSITY

Palo Alto, CA

Sustainability Data Analyst

2021 - 2022

- Derived insights for maximizing efficacy of resources management using SQL, Tableau, Snowflake, SnapLogic, Incorta

OPEX DIGITAL CONSULTING LLC

Santa Clara, CA

Energy Products Consultant - Subject Matter Expert

2020 - 2021

- Researched, engineered, and analyzed datasets for developing a comprehensive and competitive energy industry dashboard that showcases industry projects and capacity indicators across multiple energy sub-sectors.

TEXAS BUREAU OF ECONOMIC GEOLOGY | CENTER FOR ENERGY ECONOMICS

Austin, TX

Energy Economist - Research Assistant

2018 - 2020

- Built quantitative, analytical, and empirical models for NPV, decision tree, risk, sensitivity, and scenario analyses with financial real options using Monte Carlo Simulation, to evaluate economic prospects of post-FID, mid-construction energy projects in volatile market, policy environments and events like 2008, 2014 and 2020 market crashes.
- Authored a thesis whose model can estimate if such a project was heading towards bankruptcy and what alternative decision frameworks can improve the chance of success.

SOCIETY OF PETROLEUM RESOURCES ECONOMISTS

Houston, TX

Journal of Petroleum Resources Economics - Managing Editor

2018 - 2019

- Sourced, edited, and published research articles by experts in the field of energy economics for the journal's first year's 100+ page quarterly issues with a readership of 500+ in top consulting firms and universities across 5 continents.

Student Chapters - Worldwide Coordinator

2018 - 2019

- Established new student chapters in the US, India, Pakistan, and a professional chapter in Algeria.
- Mentored 10 chapters across 4 continents, led officer recruitment, coordinated monthly seminar series, grew membership across multi-disciplines, and established partnerships with other organizations and industry.

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Energy Regulatory Engineer - Air Quality

- Executed technical reviews of engineering operations of oil and gas production and refining facilities to endorse air-permits under TCEQ/EPA standards.
- Performed GHG accounting utilizing emission data and asset-level technical specifications to enforce accurate levels under the Air Quality Act.

ROBERT BOSCH DIESEL SYSTEMS

Production Engineer

Bangalore, KA

2015 - 2016

- Executed construction management of 8.7MW of solar farm to power 30% of the manufacturing plant.
- Directed supply chain operations, transitioning inventory of \$30 million annual worth, while streamlining logistical operations to reduce material inward lead time by 30%.
- Effectively reduced assembly line inefficiencies based on lean engineering while planning production operations and was awarded Continuous Improvement Award among a group of over 150 engineers in the second month at the job.

EDUCATION

UNIVERSITY OF TEXAS AT AUSTIN

Master of Science, Energy & Earth Resources

Austin, TX

2020

Certificate, Project Management (1-year program from Ethics & Leadership Institute)

2017

- A multidisciplinary STEM program in engineering, finance, economics, policy, geosciences, law, and management for interdisciplinary energy and environment solutions.
- Courses: Data Informatics/Intelligent-Systems in Geology, Decision Analysis and Application, Energy Finance, Energy Technology and Policy, Financial Valuation, Geology of Earth Resources, Law, Science, and Finance of Global Energy Transactions, Politics and Economics of International Energy.

HARVARD BUSINESS SCHOOL

Credential of Readiness, Business Management

Online

2018

- 150-hour certificate program in Business Analytics, Economics for Managers, and Financial Accounting

VISVESVARAYA TECHNOLOGICAL UNIVERSITY, INDIA

Bachelor of Engineering, Mechanical Engineering, Gold Medal

Hassan, KA

2015

- Engineering Economics and Industrial Engineering, Fluid Mechanics, Fluid Power Systems, Heat and Mass Transfer, Internal Combustion Engines, Mechanical Vibrations, Non-Conventional Resources, Operations Research, Power Plant Engineering

LEADERSHIP

SWITCH ENERGY ALLIANCE <i>Case Competition Mentor</i>	2022-2022
CLIMATE REALITY PROJECT <i>Climate Justice Advocate</i>	2020 - Present
LONGHORN ENERGY CLUB <i>Energy Forum Co-Chair</i>	2016 - 2017
TEXAS ENERGY RESOURCES GROUP <i>Corporate Relations Chair</i>	2016 - 2017
SOUL EDUCATION NON-PROFIT TRUST <i>Co-Founder and Mentor</i>	2014 - Present
BREAKTHROUGH SCIENCE SOCIETY INDIA <i>Elected State Council Member</i>	2012 - Present

AWARDS

REPSOL STEM AWARD <i>Future Leaders of The Energy Sector</i>	2018
J. N. TATA SCHOLARSHIP <i>Outstanding Indian Students Abroad</i>	2016
SARDAR VENKATA RAMAIAH GOLD MEDAL <i>Best All-Round Student in University</i>	2015
GOVERNMENT OF KARNATAKA SCHOLARSHIP <i>Undergraduate Engineering</i>	2013

Question:

DCC-5. Please provide a description of the transmission infrastructure investment required to accommodate a 15 GW increase in the Company's electric peak load. a. If the Company has evaluated the transmission infrastructure investment necessary to accommodate a different level of peak load increase, identify the specific load increase evaluated and provide a description of the transmission infrastructure investment the Company believes would be required to serve that level of peak load increase.

Response:

Objection of Counsel: Consumers Energy Company objects to this discovery request on the grounds that said request is not relevant to a determination of reasonable modification of the Company's Rate GPD tariff to allow for certain customer protections. Subject to this objection, and without waiving it, Consumers Energy responds as follows:

The Company does not design or construct transmission infrastructure. Furthermore, the Company has not requested the local Transmission Owner to conduct a study to identify the transmission infrastructure investment required to accommodate a 15 GW increase in the Company's electric peak load. The Company provides its firm load forecast to MISO for the 10-year horizon, enabling the Transmission Planner to identify necessary transmission investments.

- a. When a customer requests a significant large load addition, the Company engages with the Transmission Owner and requests a System Impact Study of the transmission system. The Company has engaged with the Transmission Owner for 2.65 GW of large load additions, which the Transmission Owner estimated would necessitate a transmission infrastructure investment of \$730-\$780 million to support the load interconnections. This estimate does not include additional transmission infrastructure required to interconnect additional generation to support the load.

As evidenced in MISO's DPP studies with increasing queue sizes, the Company anticipates that transmission investment will be exponential, rather than linear, when considering an increase from the studied 2.65 GW load additions to the requested 15 GW increase.

Witness: Laura M. Connolly

Date: April 16, 2025

Question:

21859-DCC-CE-0020. Please refer to the Company's response to DCC-5 and DCC-6 (U21859-DCC-CE-0005 and 0006). Why did Consumers engage with the Transmission Owner to evaluate 2.65 GW of large load additions (as opposed to any other amount)?

Response:

The Company engaged with the Transmission Owner on 2.65 GW of large load additions based on advanced discussions with economic development and data center projects that are considered to be more probable prospects.

Witness: Laura M. Connolly

Date: May 13, 2025

Question:

16. Please refer to Consumers' Application, paragraph 8.

- a. What power supply resources does the Company anticipate needing to procure in order to serve new data center loads?
- b. Explain how the Company determined what power supply resources the Company anticipates needing to procure to serve new data center loads.

Response:

- a. The Company anticipates a mix of renewable resources, energy-producing resources, and firm capacity resources will be needed to serve new data center loads. The specific amounts and resource types are still unknown and will be presented in the Company's next integrated resource plan ("IRP") filing, which is anticipated in quarter 2 of 2026.
- b. The requested information will be included in the 2026 IRP.

Witness: Laura M. Connolly
Date: May 30, 2025

Question:

4. The Company's recent REP (U-21816) includes, in exhibit A-6, a sales estimate peak of 8,691,153 MWh in 2032 for the Industrial LED category.

- a. How much load, in GW, does this sales estimate represent?
- b. Has the Company analyzed the impact on its RPS obligations of:
 - i. The estimated Industrial LED load indicated in response to (a)?
 - ii. 2 GW of new data center load?
 - iii. 15 GW of new data center load?
- c. Please calculate the amount of new renewable energy resources the Company will need to procure to meet its RPS obligations for each of (b)(i), (b)(ii), and (b)(iii) above.

Response:

- a. 1145 MW
- b. Yes. i) The proposed 2024 REP (U-21816) portfolio includes the necessary resources to comply with the RPS requirements for all load included in the case. ii) No. iii) No.
- c. The requested information has only been calculated for part (b)(i). The calculations for (b)(ii) and (b)(iii) may be included in the Company next Integrated Resource Plan, to the extent that those load additions are included within the range of load growth scenarios.

Witness: Laura M. Connolly

Date: June 5, 2025

Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power



Eliza Martin
Ari Peskoe

March 2025

Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power

Eliza Martin and Ari Peskoe*

Executive Summary

Some of the largest companies in the world — including Amazon, Google, Meta, and Microsoft — are looking to secure electricity for their energy-intensive operations.¹ Their quests for power to supply their growing “data centers” are super-charging a growing national market for electricity service that pits regional utilities against each other. In this paper, we investigate one aspect of this competition: how utilities can fund discounts to Big Tech by socializing their costs through electricity prices charged to the public. Hiding subsidies for trillion-dollar companies in power prices increases utility profits by raising costs for American consumers.

Because for-profit utilities enjoy state-granted monopolies over electricity delivery, states must protect the public by closely regulating the prices utilities charge for service. Regulated utility rates reimburse utilities for their costs of providing service and provide an opportunity to profit on their investments in new infrastructure. This age-old formula was designed to motivate utility expansion so it would meet society's growing energy demands.

The sudden surge in electricity use by data centers — warehouses filled with power-hungry computer chips — is shifting utilities' attention away from societal needs and to the wishes of a few energy-intensive consumers. Utilities' narrow focus on expanding to serve a handful of Big Tech companies, and to a lesser extent cryptocurrency speculators, breaks the mold of traditional utility rates that are premised on spreading the costs of beneficial system expansion to all ratepayers. The very same rate structures that have socialized the costs of reliable power delivery are now forcing the public to pay for infrastructure designed to supply a handful of exceedingly wealthy corporations.

To provide data centers with power, utilities must offer rates that attract Big Tech customers and are approved by the state's public utility commission (PUC). Utilities tell PUCs what they want to hear: that the deals for Big Tech isolate data center energy costs from other ratepayers' bills and won't increase consumers' power prices. But verifying this claim is all but impossible. Attributing utility costs to a specific consumer is an imprecise exercise premised on debatable claims about utility accounting records. The subjectivity and complexity of ratemaking conceal utility attempts to funnel revenue to their competitive lines of business by overcharging captive ratepayers. While PUCs are supposed to prevent utilities

from extracting such undue profits from ratepayers, utilities' control over rate-setting processes provides them with opportunities to obscure their self-interested strategies.

Detecting wealth transfers from ratepayers to utility shareholders and Big Tech companies is particularly challenging because utilities ask PUCs for confidential treatment of their contracts with data centers, which limits scrutiny of utilities' proposed deals and narrows the scope of regulators' options when they consider utilities' prices and terms. Meanwhile, regulators face political pressure to approve major economic investments already touted by elected officials for their economic impacts. Rejecting new data center contracts could lead potential Big Tech customers to construct their facilities in other states. Indeed, Big Tech companies have repeatedly told utility regulators that unfavorable utility rates could lead them to invest elsewhere.²

In the following sections, we investigate how utilities are shifting the costs of data centers' electricity consumption to other ratepayers. Based on our review of nearly 50 regulatory proceedings about data centers' rates, and the long history of utilities exploiting their monopolies, we are skeptical of utility claims that data center energy costs are isolated from other consumers' bills. After describing the rate mechanisms that shift utility costs among ratepayers, we explain how both existing and new rate structures, as well as secret contracts, could be transferring Big Tech's energy costs to the public. Next, we provide recommendations to limit hidden subsidies in utility rates. Finally, we question whether utility regulators should be making policy decisions about whether to subsidize data centers and speculate on the long-term implications of utility systems dominated by trillion-dollar software and social media companies.

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I. Government-Set Rates Incentivize Utilities to Pursue Data Center Growth at the Expense of the Public

Data centers are large facilities packed with computer servers, networking hardware, and cooling equipment that support services like cloud computing and other data processing applications. While data centers have existed for decades, companies are now building much larger facilities. In 2023, companies began developing facilities that will consume hundreds of megawatts of power, as much as the city of Cleveland.³ As several companies race to develop artificial intelligence (AI), the scale and energy-intensity of data center development is rapidly accelerating. By the end of 2024, companies started building gigawatt-scale data center campuses and are envisioning even larger facilities that will demand more energy than the nation's largest nuclear power plant could provide.⁴

The sudden and anticipated near-term growth of cloud computing infrastructure to accommodate the development of AI is driving a surge of utility proposals to profit from Big Tech's escalating demands. By 2030, data centers may consume as much as 12 percent of all U.S. electricity and could be largely responsible for *quintupling* the annual growth in electricity demand.⁵ This growth is likely to be concentrated in regions with robust access to telecommunications infrastructure and where utilities pledge to quickly meet growing demand. Data centers could substantially expand utilities' size, both financial and physical, as they develop billions of dollars of new infrastructure for Big Tech.⁶

Data center growth is overwhelming long-standing approaches to approving utility rates. Nearly every consumer pays for electricity based on the utilities' average costs of providing service to similar ratepayers. A handful of special interests, particularly large industrial users, pay individualized rates that are negotiated with the utility and often require PUC approval. Data center growth could flip the current ratio of consumers paying general rates to special-interest customers paying unique contracts pursuant to special contracts. In this section, we summarize the potential for massive data center growth and then explore how this growth is challenging long-standing ratemaking practices and is causing the public to subsidize Big Tech's power bills.

A. Utilities Are Projecting Massive Data Center Energy Use

Industry experts and utilities are forecasting massive data center growth, and their projections keep going up. In January 2024, one industry consultancy projected 16 GW of new data center demand by 2030.⁷ But by the end of the year, experts were anticipating data center growth to be as high as 65 GW by 2030.⁸ Individual utilities are even more bullish. For example, Georgia Power anticipates its total energy sales will nearly double by

the early 2030s, a trend it largely attributes to data centers.⁹ In Texas, Oncor announced 82 gigawatts of potential data center load,¹⁰ equivalent to the maximum demand of Texas' energy market in 2024.¹¹ Similarly, AEP, whose multi-state system peaks at 35 GW, expects at least 15 GW of new load from data center customers by 2030,¹² although AEP's Ohio utility added that "customers have expressed interest" in 30 GW of additional data centers in its footprint.¹³

There are reasons, however, to be skeptical of utilities' projections. Utilities have an incentive to provide optimistic projections about potential growth; these announcements are designed in part to grab investors' attention with the promise of new capital spending that will drive future profits.¹⁴ When pressed on their projections, utilities are often reticent to disclose facility-specific details on grounds that a data center's forecasted load is proprietary information.¹⁵ This secrecy can lead utilities and analysts to double-count a data center that requests service from multiple utilities.¹⁶ To acquire power as quickly as possible, data center companies may be negotiating with several utilities to discover which utility can offer service first.

Technological uncertainty further complicates the forecasting challenge. Future innovation may increase or decrease data centers' electricity demand. The current surge in data center growth is traceable to the release of ChatGPT in 2022 and the subsequent burst of AI products and their associated computing needs.¹⁷ Computational or hardware advancements might reduce AI's energy demand and diminish data center demand.¹⁸ For instance, initial reports in January 2025 about the low energy consumption of DeepSeek, a ChatGPT competitor, fueled speculation that more efficient AI models might be just as useful while consuming far less energy. Even if more energy efficient AI models materialize, however, their lower cost could lead consumers to demand more AI services, which could drive power use even higher.¹⁹

Nonetheless, investment is pouring into data center growth. At a January 21, 2025 White House press conference, OpenAI headlined an announcement of \$100 billion in data center investment with the possibility of an additional \$400 billion over four years.²⁰ Earlier that month, Microsoft revealed that it would spend \$80 billion on data centers in 2025, including more than \$40 billion in the U.S.²¹ Two weeks earlier, Amazon said it would spend \$10 billion on expanding a data center in Ohio.²² And two weeks before that, Meta announced its own \$10 billion investment to build a new data center in Louisiana.²³

While the scale and pace of data center growth is impossible to forecast precisely, we know that utilities are projecting and pursuing growth. In the next section, we explore the ratemaking and other regulatory processes that socialize utilities' costs and risks. Unlike

companies that face ordinary business risks to their profitability, utilities rely on government regulators to approve their prices and can manipulate rate-setting processes to offer special deals to favored customers that shift the costs of those discounts to the public. This “hidden value transfer,” a term coined by Aneil Kovvali and Joshua Macey, is a strategy employed by monopolist utilities to increase profits at the expense of their captive ratepayers.²⁴ Regulators are supposed to protect against hidden value transfers by aligning rates with the costs utilities incur to serve particular types of consumers. But this rate design strategy is rife with imprecision. In reality, ratepayers are paying for each other’s electricity consumption, and data center growth could potentially exacerbate the cross-subsidies that are rampant in utility rates.

B. Utility Rates Socialize Power System Costs Using the “Cost Causation” Standard

The U.S. legal system bestows significant economic advantages on investor-owned utilities (IOUs), which are for-profit companies that enjoy state-granted monopolies to deliver electricity. Government-approved electricity prices reimburse utilities for their operational expenses and provide utilities an opportunity to earn a fixed rate of return on their capital investments. With a monopoly service territory and regulated prices designed to facilitate earnings growth, a utility is insulated from many ordinary business risks and shielded from competitive pressures.

Public utility regulators, or PUCs, must protect the public from a utility’s monopoly power and, in the absence of competition, motivate the company to provide reliable and cost-effective service. To meet those goals, PUCs determine whether utility service is offered to all consumers within a utility’s service territory at rates and conditions that are “just and reasonable.”²⁵ This standard, enshrined in state law, requires PUCs to balance captive consumers’ interests in low prices and fair terms of service against the utility’s interest in maximizing returns to its shareholders. A utility rate case is the PUC’s primary mechanism for weighing these competing interests by setting equitable prices for consumers that provide for the utilities’ financial viability.

“Cost causation” is a guiding principle in ratemaking that dictates consumer prices should align with the costs the utility incurs to provide service to that customer or group of similar ratepayers. By approving rates that roughly meet the cost causation standard, PUCs prevent “undue discrimination” between utility ratepayers, a legal requirement that is typically specified in state law.

While the PUC makes the final decision to approve consumer prices, the utility drives the ratemaking process. In a rate case, the utility’s primary goal is to collect enough money to

cover its operating expenses and earn a profit on its capital investments. A utility proposes new rates by filing its accounting records and other data and analysis that form the basis of its preferred prices. Once it establishes its “revenue requirement,” the utility then proposes to divide this amount among groups of consumers based on their usage patterns, infrastructure requirements, and other characteristics that the utility claims inform its costs of providing service to those consumers. Typical groups, also known as ratepayer classes, include residential, commercial, and industrial consumers. Finally, the utility proposes standardized contracts known as tariffs for each ratepayer class that include uniform charges and terms of service for each member of that ratepayer class.

Under this ratemaking process, residential ratepayers often pay the highest rates because they are distributed across wide areas, often in single-family homes that consume little energy.²⁶ The utility recovers the costs of building, operating, and maintaining its extensive distribution system to serve residential ratepayers by spreading those costs over the relatively small amount of energy consumed by households. By contrast, an industrial consumer uses far more energy than a household and is likely connected to the power system through higher voltage lines and needs less local infrastructure than residential ratepayers. The utility can distribute lower total infrastructure costs over far greater energy sales to generate a lower industrial rate. Properly designed rates should “produce revenues from each class of customers which match, as closely as practicable, the costs to serve each class or individual customer.”²⁷

But ratemaking is not “an exact science,” and there is not a single correct result.²⁸ In a utility rate case, various parties advocate for their own self-interest by contesting the utility’s filing. Consumer groups and other parties urge the PUC to reduce the utility’s revenue requirement, which could potentially lower all rates. But once the revenue requirement is set, consumer groups are pitted against each other as they try to reduce their share of the total amount. Their arguments are based on competing approaches to cost causation, with each party claiming that lower rates for itself align with economic principles, fairness, and other subjective values. Well-resourced participants, such as industrial groups that have a significant incentive to argue for lower power costs, hire lawyers and analysts to comb through the utility’s filings and argue that their rates should be lower.

But parties face an uphill battle challenging the utility’s accounting records, engineering studies, and other evidence the utility files to justify its preferred rates. Because it initiates the rate case and generates the information needed for the PUC to approve a rate, the utility is inherently advantaged. The information asymmetry between utilities and other parties, as well as the imprecision and subjectivity of the cost causation standard, can facilitate

subsidization across classes of ratepayers. We highlight three reasons that PUCs may purposefully or unwittingly approve rates that depart from the cost causation standard.

First, attributing the utilities' costs to various ratepayer classes depends on contested assumptions and disputed methodologies. Different approaches to cost allocation will yield different results. As a pioneer in public utility economics once explained, there are "notorious disagreements among the experts as to the choice of the most rational method of [] cost allocation — a disagreement which seems to defy resolution because of the absence of any objective standard of rationality."²⁹ Parties, including the utility, provide the PUC with competing analyses that are designed to meet their own objectives. For instance, industrial consumers will sponsor a study that concludes lower rates for the industrial rate class is consistent with the cost causation principle. Other parties favor their own interests in what can be a zero-sum game over how to divide the utility's revenue requirement.

Second, the PUC may have its own preferences. In most states, utility commissioners are appointed by the governor, but in ten states they are elected officials. Either commissioner may face political pressure to favor a particular ratepayer class. For instance, an elected commissioner may be inclined to provide lower rates to residential ratepayers who will vote on the commissioner's reelection. An appointed commissioner may choose to align utility rates with a governor's economic development agenda by providing lower rates to major employers, such as the commercial or industrial class. Other pressures may bias regulators in favor of other interests. As it weighs competing evidence about cost allocation provided by various parties in a rate case, the PUC has discretion to find a particular study more credible and may choose a rate structure that aligns with the sponsoring party's goals and the PUC's own preferences. While other parties may challenge a PUC's decision in court, courts are unlikely to overturn a PUC's judgment about cost allocation.³⁰

Third, the utility may exploit its informational advantages and intentionally provide false information. A rate case is premised on detailed accounting records filed by the utility about the expenses it incurs to provide service. The spreadsheets and other information that the utility files are based on internal records not available to the PUC or rate-case parties. Even if the utility provides some of its records in response to a party's request, the information might be too voluminous for the PUC or other parties to verify. Ultimately, the PUC relies on the utility's good faith. However, recent cases show that utilities are filing fabricated or misleading records.³¹

A random audit of multi-state utility company FirstEnergy by the Federal Energy Regulatory Commission (FERC) found that the utility had hidden lobbying expenses tied to political corruption by mislabeling them as legitimate expenses in its accounting books. According to

the audit, the utility's internal controls had been "possibly obfuscated or circumvented to conceal or mislead as to the actual amounts, nature and purpose of the lobbying expenditures."³² The audit concluded that the utility's mislabeling allowed the inappropriate lobbying expenses to be included in rates.³³ Rate cases did not detect this deception. Only an audit, informed by an extensive federal sting operation, revealed the utility's deceit. Regulators have recently uncovered other utilities filing false or misleading information in regulated proceedings.³⁴

Once the regulators approve utility rates, some consumers can shift costs to other ratepayers by fine-tuning their energy consumption. As we discuss in more detail in part II.B.3, rates for commercial and industrial ratepayers typically include demand charges that are tied to each consumer's energy consumption during the utility's or regional power system's moment of peak demand that year. By anticipating when that peak will happen and reducing consumption of utility-delivered power at that moment, a data center or other energy-intensive consumer can substantially reduce its bill. While this "peak shaving" can reduce power prices for other consumers, it also forces other ratepayers to pay part of the energy-intensive consumer's share of infrastructure costs.

Despite its flaws, ratemaking continues to be the dominant approach to financing power sector infrastructure. Uniform, stable prices provide predictable revenue that motivates investors to fund utility expansion. Rate regulation typically insulates investors from many ordinary business risks by putting ratepayers on the hook for the company's engineering, construction, or procurement mistakes. For instance, regulators often allow utilities to increase rates when their projects are over-budget. The utility rarely faces financial consequences for missteps that would cause businesses that rely on competitive markets to lose profits.

Some energy-intensive consumers can be exempted from this ratemaking process that socializes costs and shifts risks to the public. The special rates for these consumers are set in one-off agreements that can lock in long-term prices and shield it from risks faced by other ratepayers. These contracts, which typically require PUC approval, allow an individual consumer to take service under conditions and terms not otherwise available to anyone else. Special rates are, in essence, "a discriminatory action, but one that regulators can justify under certain conditions."³⁵

To protect ratepayers, some state laws authorizing special contracts require PUCs to evaluate whether the contract meets the cost causation standard.³⁶ However, the "notorious disagreements" about how to measure whether a consumer is paying for its costs of service still plague the special-contract cost causation analysis. And, as we describe

below, proceedings about special contracts present unique obstacles to evaluating cost causation.

In other states, however, laws authorizing special contracts do not prevent PUCs from approving below-cost contracts. For instance, Kansas law allows regulators to approve special rates if it determines that the rate is in the state's best interest based on multiple factors, including economic development, local employment, and tax revenues.³⁷ A recent law enacted in Mississippi strips utility regulators of any authority to review contracts between a utility and a data center.³⁸

Regardless of the standard for reviewing special contracts, there is significant political pressure on regulators to approve these deals, even if such development results in higher electricity costs for other ratepayers. Regulators do not want to be seen as the veto point for an economic development opportunity, which may have already been publicized by the company and the governor. Because utilities may be competing for the profitable opportunity to serve a particular energy-intensive consumer, they have an incentive to offer low prices, even if that reduced rate results in higher costs for the utility's other ratepayers. As noted, despite their wealth, Big Tech companies seek low energy prices and make siting decisions based in part on price.³⁹ Regulatory scrutiny of special contracts is therefore a critical backstop for protecting ratepayers.

II. How Data Center Costs Creep into Ratepayers' Bills

When a utility expands its system in anticipation of growing consumer demand, it typically seeks to include the capital costs of new infrastructure in its rates. If approved, ratepayers share the costs of the utility's expansion pursuant to a cost allocation formula accepted by the PUC. This approach, while imperfect for the reasons described in the previous section, has facilitated population growth and economic development by forcing ratepayers to subsidize new infrastructure that will allow new residents and businesses to receive utility-delivered energy.

For many utilities, their expectations about growth are now dominated by new data centers. Rather than being dispersed across a utility's service territory like homes and businesses, these new data center consumers that are benefitting from utility expansion are identifiable and capable of paying for infrastructure that will directly serve their facilities. If PUCs allow utilities to follow the conventional approach of socializing system expansion, utilities will impose data centers' energy costs on the public. The easiest way for utilities to shift data centers' energy costs to the public is to simply follow long-standing practices in rate cases.

In our view, however, utilities are often using more subtle ratemaking methods to push data centers' energy costs onto consumers' bills.

In this section, we focus on three mechanisms that can force consumers to pay for data center's energy costs. First, special contracts between utilities and data centers, approved through opaque regulatory processes, are transferring data center costs to other consumers. Second, disconnected processes for setting federally regulated transmission and wholesale power rates and state-set consumer prices are: A) causing consumers to pay for interstate infrastructure needed to accommodate new data centers; B) putting consumers on the hook for new infrastructure built for data-center load that never materializes; and C) allowing data centers to strategically reduce energy usage during a few hours to reduce their bills and shift costs to other consumers. Third, data centers that bypass traditional utility ratemaking by contracting directly with power generators may also be raising electricity prices for the public. These co-location agreements between a data center and adjacent non-utility generator may trigger an increase in power market prices and distort regulated electricity delivery rates.

A. Shifting Costs through Secret Contracts

Special contracts are offered by utilities to energy-intensive consumers to attract their business. While regulators in many states are required to protect the public from such cutthroat practices that harm ratepayers, we explain in this section why we are skeptical about utility claims that special contracts for data centers do not force the public to pay for Big Tech's energy costs.

Our review of 40 state PUC proceedings about special contracts with data centers finds that regulators frequently approve special contracts in short and conclusory orders. While PUC rate case decisions are lengthy documents that engage with the evidence filed by the utilities and other parties, most PUC orders approving special contracts provide only cursory analysis of the utility's proposal. One challenge for PUCs is that few, if any, parties participate in these proceedings. As a result, the PUC has little or no evidence in the record to compete with the utility's claim that the contract isolates data center energy costs from other ratepayers' bills.

The PUC often deters parties from arguing against the utility's proposed special contract by reflexively granting utility requests to shield its proposal from public view.⁴⁰ The PUC's own grant of confidentiality adds a procedural barrier to greater participation and prevents the public from even attempting to calculate the potential costs of these deals.⁴¹ But perhaps the greater impediment to third-party analysis of proposed special contracts is that

ratepayers believe that they have little at stake in the proceedings. Unlike rate cases, which set the prices consumers pay, a special contract will only have indirect financial effects on other ratepayers if it shifts costs that the energy-intensive customer ought to pay on to other ratepayers' bills. Because meaningfully participating in a special contract case has a high cost and a generally low reward, otherwise interested parties have typically not bothered to contest them. But the scale of data center special contracts demands attention because the costs being shifted to the public could be staggering.

A special contract shifts costs to other ratepayers when the customer pays the utility a price lower than the utility's costs to serve that customer. To cover the shortfall, utilities will attempt to raise rates for other ratepayers in a subsequent rate case.⁴² The amount of the shortfall, and whether there is any shortfall at all, depends on how the utility calculates its costs of providing service to the data center. As discussed above, there are "notorious disagreements" about appropriate methodologies, and even the term "cost" can itself be subject to dispute. Experts debate, for instance, when to use average or marginal costs and whether short- or long-term costs are suitable metrics. When utilities use one metric in a rate case and another metric in a special contract proceeding, they could be causing spillover effects that harm ratepayers.⁴³

The disagreements about methodologies and complexities of the calculations underscore a foundational challenge to reviewing a special contract rate. As discussed above, PUC rate case decisions do not purport to assign utility costs to individual consumers but instead apportion cost responsibility among similar ratepayers grouped together as classes. But in a special contract proceeding, the utility makes the unusual claim that it can isolate its costs to serve a single consumer. Without contrary evidence filed by interested parties, the PUC may have little basis for rejecting the utility's analysis.

Even without the benefit of third-party analyses in special contract proceedings, PUC orders may summarize cross-subsidy concerns raised by their own staff. But challenging the utility's analysis is costly and time-intensive, and staff may not have the resources to provide robust analysis. Similarly, state ratepayer advocates occasionally participate in these proceedings and raise cross subsidy arguments, but they are also often stretched too thin to provide a detailed response to the utility's proposal. As a result, we find that many PUC orders approving special contracts simply conclude that the proposed contract is reasonable without meaningfully engaging with the proposal.⁴⁴

Such PUC orders are therefore not persuasive in assuaging concerns that the public may be subsidizing Big Tech's energy costs. Moreover, as discussed, state regulators may face political pressure not to veto a significant construction project in the state. The utility's

assertion that it is protecting other ratepayers may provide enough cover for regulators to approve a special contract. The obscurity and complexity of these proceedings provides utilities with opportunities to hide data center energy costs and force them onto other consumers' bills.

Recent litigation against Duke Energy, one of the largest utilities in the country, exposed that the company was acting on its incentive to shift costs of a special contract to its other ratepayers. Duke's scheme responded to a new power plant developer offering competitive contracts to supply small non-profit utilities that had been purchasing power from Duke.⁴⁵ Duke's internal documents disclosed through litigation revealed that the new company was far more efficient than Duke and the utility therefore could not compete for customers based on price. Nonetheless, Duke offered one of its larger customers a new contract that amounted to a \$325 million discount compared to its existing deal with Duke.⁴⁶ Additional internal utility documents revealed that Duke developed a plan to "shift the cost of the discount" to its other ratepayers by raising their rates.⁴⁷ Duke's strategy to force its ratepayers to subsidize the special-contract customer's energy was discovered only because the power plant developer sued Duke in federal court under antitrust law.

While our paper focuses on how consumers are likely subsidizing Big Tech's energy costs through their utility rates, we acknowledge that the reverse is also theoretically possible. A data center taking service under special contracts could be *overpaying*. A utility proposing a special contract might prefer to overcharge one deep-pocketed customer through a special contract in order to reduce rates for the public. While this pricing strategy may seem politically attractive for the utility and PUC, it seems unlikely to attract new data centers.

Regardless of a utility's motivation, regulators are supposed to be skeptical of a sudden surge in utility spending. Superficial reviews of special contracts are insufficient when they are collectively committing utilities to billions of dollars for Big Tech customers. The recent Duke litigation illustrates how utilities take advantage of their monopolies to force ratepayers into subsidizing their competitive lines of businesses. Discounted rates can give a utility an edge in the data center market,⁴⁸ and hiding the costs of discounts in ratepayers' bills boosts utility profits. To prevent utilities from overcharging captive ratepayers for the benefit of their competitive businesses, both PUCs and FERC have developed regulatory mechanisms that attempt to prevent such subsidies.⁴⁹ For instance, FERC applies special scrutiny to contracts between utilities and power plants that are owned by the same corporate parent. FERC's concern is that because state regulators must let the utility recover its FERC-regulated costs in consumer's rates, "such sales could be made at a rate that is too

high, which would give an undue profit to the affiliated [power plant] at the expense of the franchised public utility's captive customers."⁵⁰

Special contracts with data centers are the latest iteration of a long-standing problem with monopolist utilities. Policing cost-shifts in this context is particularly challenging due to the opaque nature of the proceedings, the complexity and subjectivity of assessing the utility's costs of serving an a single consumer, and political pressure on PUCs to approve contracts.

B. Shifting Costs through the Gap Between Federal and State Regulation

When a PUC approves a utility's revenue requirement, it must allow the utility to include interstate transmission and wholesale power market costs that are regulated by FERC.⁵¹ In much of the country, utilities procure power through markets administered by non-profit corporations called Regional Transmission Organizations (RTOs). Market prices are influenced by a host of factors, such as fuel and technology costs, and ultimately reflect generation supply and consumer demand. If supply is constrained by a data center demand surge, market prices would likely increase, at least in the short term. Consumers' utility bills will include these higher power market prices.

PUCs can protect ratepayers from market price increases by allocating the costs of higher prices to data centers. But PUCs rarely order utilities to adjust the formulae that spread FERC-regulated market and transmission costs to ratepayers. In this section, we illustrate how ratepayers can pay more for power due to data center demand by focusing on FERC-regulated transmission costs. Federal law provides FERC with exclusive authority to set utilities' transmission revenue requirements and allocate a utility's transmission revenue requirement to multiple utilities. Under FERC's rules, costs of a new transmission line can be paid entirely by a single utility or shared among utilities if there is agreement that the new line benefits multiple utilities. When costs are shared, a region-specific formula approved by FERC divides costs roughly in proportion to the power system benefits each utility receives, such as lower market prices and improved reliability.⁵²

Under either the single-utility or multi-utility approach, PUCs apply their own formula for dividing FERC-allocated transmission costs among ratepayer classes. These separate cost allocation schemes can allow data center energy costs to creep into other consumers' bills when new data centers trigger a need for transmission upgrades. We illustrate by discussing examples of each type of transmission cost recovery and then explain how rate designs embedded in special contracts or tariffs can allow data centers to reduce their bills at the expense of ratepayers.

1. Separate Federal and PUC Transmission Cost Allocation Methods Allow Data Center Infrastructure Costs to Infiltrate Ratepayers' Bills

In December 2023, the PJM RTO, a utility alliance stretching from New Jersey to Chicago and south to North Carolina, approved \$5 billion of transmission projects whose costs would be shared based among PJM's utility members.⁵³ PJM identified two factors driving the need for this transmission expansion: retirement of existing generation resources and "unprecedented data center load growth," primarily in Virginia.⁵⁴ Pursuant to its FERC-approved cost allocation method, PJM split half of the transmission costs across its footprint based on each utilities' share of regional power demand and allocated the remaining half using a computer simulation of the regional transmission network that estimates benefits each utility receives from the new transmission projects.⁵⁵ Under this approach, PJM assigned approximately half of the total cost to Virginia utilities, approximately 10% to Maryland utilities, and the remainder to utilities across the region.⁵⁶

Each state's PUC then allocates the costs assigned by PJM to ratepayer classes of each utility it regulates. In Maryland, across the state's three IOUs assign, an average of 66 percent of transmission costs are assigned to residential ratepayers.⁵⁷ The larger of Virginia's two IOUs includes more than half of its transmission costs in residential rates.⁵⁸ Thus, in both states, residential ratepayers are paying the majority of regional transmission costs that are tied to data center growth. From the public's perspective, this result appears to violate the cost causation principle. After all, residential ratepayers are not causing PJM to plan new transmission.

PJM's approach, however, recognizes that new regional transmission benefits all ratepayers by improving reliability, allowing for more efficient delivery of power, and providing other power system improvements that are broadly shared. PJM developed its cost-sharing approach with the understanding that new transmission would be designed primarily to provide public benefits. New transmission designed for a few energy-intensive consumers, and not broad public benefits, is inconsistent with PJM's premise. That said, by increasing transmission capacity, new regional transmission lines for data centers may provide ancillary benefits to all ratepayers. PJM's power system simulation, which it uses to allocate half the costs of transmission expansion, demonstrates the shared benefits of this new infrastructure. Proponents of transmission expansion argue that such power flow models validate the current approach of allocating transmission costs to benefiting ratepayers because the models can calculate with reasonable accuracy who benefits from new transmission and therefore who should pay for it.

But even assuming that ancillary benefits for all ratepayers are adequate to justify current methods for regional transmission cost allocation, PJM only spreads costs among the region's utilities. Each utility then has its own methods, approved by PUCs, for allocating transmission investment to its ratepayers. The PUC-approved methods typically presume that ratepayers share in the benefits of new transmission in proportion to their total energy consumption. This approach causes residential ratepayers in Maryland, which consume more than half of the state's electricity, to pay for the lion's share of Maryland utilities' costs of new PJM-planned transmission. Without reforms, consumers will be paying billions of dollars for regional infrastructure that is designed to address the needs of just a few of the world's wealthiest corporations.⁵⁹

Obsolete PUC cost allocation formulas can also cause ratepayers to pay for transmission costs that are not regionally shared. For instance, in July 2024, Virginia's largest utility applied to the PUC for permission to build infrastructure that would serve a new large data center. PUC staff reviewing the proposal found that but for the data center's request, the project "likely, if not certainly, would not be needed at this time."⁶⁰ In its application, the utility told state regulators that the \$23 million project would be paid for through its FERC-approved transmission tariff.⁶¹ Under the utility's existing state-approved tariff, about half of all costs assigned through the FERC-regulated tariff are billed to residential ratepayers, and the remaining half are billed to other existing ratepayers.⁶² The bottom line is that existing tariffs force the public to foot the bill for the data center's transmission.

2. Utilities May Be Saddling Ratepayers with Stranded Costs for Unneeded Transmission

If a utility's data center growth projections fail to materialize, ratepayers could be left paying for transmission that the utility constructed in anticipation of data center development. Claiming that it was addressing this "stranded cost" issue, American Electric Power (AEP) of Ohio proposed a new state-regulated tariff that that would require data center customers to enter into long-term contracts with the utility before receiving service. AEP's proposed contract would require the data center to pay 90 percent of costs associated with its maximum demand for a ten-year period, including FERC-regulated transmission costs.⁶³ According to the utility, this upfront guarantee protects AEP's other ratepayers from the risk that the utility builds new infrastructure for a data center that never materializes and prevents the utility from offloading all of these "stranded" costs on other ratepayers.

While these long-term contracts would at least partially insulate AEP's ratepayers from data center transmission costs, neighboring utilities pointed out that they could still be left paying

for stranded costs through PJM's allocation of transmission investments. Their protests explain that if AEP builds new transmission lines in anticipation of data center load growth, and those lines are paid for via PJM's regional cost allocation, then those costs would be split among all PJM-member utilities. As noted, PJM allocates half the costs of new transmission lines to its utility members based on their share of regional energy sales. If AEP's data center customers commence operations, AEP's own share of regional transmission costs would increase in proportion to its rising share of regional energy sales. In that scenario, other utilities in the region may not overpay for transmission needed for AEP's data center customers.

Protesting utilities in the Ohio PUC proceeding focus on the possibility that AEP's data center customers cancel their projects or consume less energy than anticipated after AEP has spent money developing new transmission to meet projected data center demand.⁶⁴ Under that scenario, total regional transmission costs would rise due to AEP's spending, but AEP's share of total costs would not increase proportionally. As a result, other regional utilities would face increasing costs to pay for infrastructure developed to meet AEP's unrealized data center energy demand. How much individual consumers pay for the new infrastructure would depend on how each utility allocates transmission costs to various ratepayer classes pursuant to a PUC rate case decision.

New transmission projects paid for by a single utility can also raise stranded cost concerns. In December 2024, FERC approved a contract that governed the construction of transmission facilities needed to provide service to a new data center.⁶⁵ Under the contract, the data center will immediately pay for new infrastructure needed to connect the facility to the existing transmission network but will not directly pay for necessary upgrades to existing transmission facilities. Instead, the utility AES pledged to include those upgrade costs in the transmission rates paid by all ratepayers through a subsequent regulatory process. A separate state-regulated tariff for energy-intensive consumers would require the data center, and not other consumers, to ultimately pay for the upgrades. In addition, the contract requires the data center to pay for the upgrades in the event it does not commence operations or uses less energy than would be required under the state-regulated tariff to pay for the upgrades over the time. Our understanding is that this approach to transmission cost recovery for new energy-intensive consumers is fairly common and not limited to data centers, but ratepayer advocates are concerned that data centers' commitments may be more uncertain than other types of energy-intensive consumers.

The Ohio ratepayer advocate therefore protested the contract, arguing that the language protecting other consumers from paying for the transmission upgrades was "unacceptably

ambiguous.”⁶⁶ The Ohio advocate urged FERC to require “specific language to preclude shifting data center costs” to other consumers.⁶⁷ FERC nonetheless approved the contract because it found that these concerns were premature and noted that they may be raised in future proceedings that directly address any proposed cost shifts.⁶⁸ In a short concurrence, FERC Commissioner Mark Christie questioned whether the rate treatment proposed by the utility that could burden consumers with stranded costs is justified.

3. By Slightly Reducing Their Energy Use, Data Centers Can Increase Ratepayers’ Transmission and Wholesale Market Charges

Like other ratepayers, data centers pay an energy price for each unit of energy they consume as well as a monthly flat fee. Data centers, and many non-residential ratepayers, also face utility-imposed demand charges that are tied to their peak consumption during a specified month, year, or other time period. These charges are intended to reflect the costs of building power systems that have sufficient capacity to generate and deliver energy when consumer demand is unusually high. In RTO regions, PUC-regulated data center special contracts and tariffs likely reflect FERC-approved demand charges that incorporate regional transmission costs and may also include costs of procuring sufficient power plant capacity to meet peak demand. By reducing their energy use during just a few hours of the year, data centers may be able to reduce their share of regional costs that are allocated to demand charges and effectively force other ratepayers to pick up the tab.

Electricity use is constantly changing, and it peaks when consumers ramp up cooling and heating systems during exceptionally hot or cold days. Meeting these moments of peak demand is very expensive. Consumers pay for transmission and power plant infrastructure that is mostly unused but nonetheless necessary for providing power during a few peak hours each year. While utilities have employed several methods for assessing demand charges, many energy-intensive consumers are billed based on their own consumption at the moment the regional system reaches its peak demand.⁶⁹

Data centers and other large energy users have significant incentives to forecast when this peak hour will occur and reduce their consumption of utility-delivered power during that hour. To avoid shutting down or reducing their production during hours when the system might hit its peak, energy-intensive consumers may install backup generators that displace utility-provided power. Large power users may already have their own power generators to protect against outages or improve the quality of utility-delivered power.⁷⁰ Needless to say, most consumers that face demand charges, such as small businesses, do not have a sufficient incentive to forecast the system peaks or install on-site generation. As data

centers' share of regional energy consumption grows, Big Tech will be able to shift an increasingly large share of the region's costs to other ratepayers, particularly if their demand charges are easily manipulable.

PUCs can often prevent these cost shifts among consumers who take service from rate-regulated utilities in their states. Federal law requires only that the total costs allocated through FERC-approved tariffs must be passed on to utilities and then ultimately to consumers through PUC-regulated tariffs or special contracts. PUCs can choose their own methods for allocating those costs among ratepayers. Because data centers' special contracts are confidential, we often do not know whether utilities and PUCs are facilitating cost shifts through demand charges. Whether data centers are taking service under tariffs or special contracts, PUCs should ensure that rate structures are not allowing data centers to shift costs through manipulable demand charges.

That said, as we discuss below in part III.E, cutting peak consumption can reduce costs for everyone if utilities build their systems for a lower peak that accounts for a data center's ability to turn off or self-power. The problem is that utilities are expanding based on an assumption that data centers will operate at full power with utility-delivered power during peak periods. When a data center uses its own generation during peak periods to avoid demand charges, it is shifting the costs of an overbuilt system to the public.

C. Shifting Costs by "Co-Locating" Data Centers and Existing Power Plants

Power plant owners have developed their own scheme for attracting data centers that could shift energy costs from data centers to ratepayers. Under "co-location" arrangements, a data center connects directly to an existing power plant behind the plant's point of interconnection to the utility-owned transmission network. By delivering and taking power without using the transmission network, power plant owners and data centers argue that they ought to be exempt from paying utility-assessed energy delivery fees. Utilities have contested this arrangement because it denies them profitable opportunities to build new infrastructure to connect data centers to their networks.

In their haste to secure power as quickly as possible, data centers are looking to contract with existing generation, particularly nuclear power plants. By connecting directly to a power plant, data centers aim to avoid a potentially lengthy process administered by a utility to connect the data center to the utility's power delivery system. Locating load behind a power plant's point of delivery to the transmission network is not new. But the potential scale of data center growth and possibility that some significant share of that growth will co-locate has spawned disputes between power plant owners and utilities.

We highlight the key points about co-location by focusing on regulatory proceedings that involve Constellation, the largest owner of nuclear plants in the U.S., and Exelon, the largest utility in the U.S. that owns only delivery infrastructure and not power plants. Until 2022, Constellation and Exelon were housed under the same corporate parent. The company's restructuring into separate generation and delivery companies allows each of those businesses to independently pursue policies that best meet their financial interests. Data center growth began to rapidly escalate shortly thereafter and has revealed tensions between utilities and companies that compete in wholesale electricity markets for profits.

Co-location is a vague term. Because financial consequences will follow from any regulatory definition of co-location, utilities and power generators dispute how co-location technically functions. Constellation claims that because a data center co-located with one of its nuclear plants cannot receive power from the grid, it is therefore "fully isolated" from the transmission network.⁷¹ Exelon counters that "as a matter of physics and engineering," the co-located data center is "fully integrated with the electric grid."⁷² Utilities and other parties point out that a nuclear plant must operate in sync with the other plants connected to the transmission network and claim that the data center benefits from this arrangement even if the transmission system is not delivering power to it.⁷³

This technical distinction could affect whether co-located entities are utility ratepayers that pay for delivery service. Constellation argues that because the utility is not delivering energy to the data center, the data center is not a utility customer, and it should not have to pay any FERC- or PUC-regulated delivery charges. Exelon opposes that result and has estimated that a single proposed co-location arrangement between a nuclear owner and a data center would shift between \$58 million and \$140 million of transmission and state-regulated distribution charges to other ratepayers.⁷⁴

But Constellation and other generators dispute that calculation, claiming that this "phantom . . . 'cost shift' is, at best, merely a back-of-the-envelope estimate" of the revenue a utility would collect if the data center signed up as its customer.⁷⁵ Co-location, according to the nuclear plant owners, does not actually cause other ratepayers to pay higher transmission rates but instead precludes them from receiving lower delivery rates that they might pay when a new energy-intensive customer becomes a utility ratepayer and pays its proportional share of the utility's cost of service (a hypothetical that likely does not occur when the new customer receives a one-off price pursuant to a special contract).

But analysts are concerned that co-location can actually raise prices in interstate power markets. Across much of the country, generators are constantly competing through auction markets to supply power. In a few regions, market operators conduct separate annual,

monthly, or seasonal auctions for capacity to procure sufficient resources for meeting peak consumer demand. Each power plant can offer capacity into the auction equivalent to its maximum potential for energy generation. In the PJM region, nuclear plants accounted for 21 percent of total capacity that cleared the most recent auction.⁷⁶

PJM's independent market monitor, who fiercely promotes and defends PJM's markets, recently warned that colocation could "undermine" PJM's markets. He posited that if all nuclear plants in the region attracted co-located customers, "the impact on the PJM grid and markets would be extreme. Power flows on the grid that was built in significant part to deliver low-cost nuclear energy to load would change significantly. Energy prices would increase significantly as low-cost nuclear energy is displaced by higher cost energy . . . Capacity prices would increase as the supply of capacity to the market is reduced."⁷⁷ Should this scenario play out, the region's ratepayers could be forced to pay higher prices due to data centers' purchasing decisions. However, as noted, steep increases in demand due to data center growth could increase wholesale market prices regardless of whether data centers co-locate with existing power plants.

For utilities, opposing co-location is not purely about protecting their ratepayers or upholding the integrity of interstate markets. Co-location threatens their control over power delivery by allowing data centers to take energy directly from a large power producer. In some states, utilities might claim that state laws prohibit co-location because they provide the utility with a monopoly on retail sales.⁷⁸ Co-location would also reduce the profits that utilities would otherwise stand to gain from constructing new infrastructure to serve data centers.

In an ongoing FERC proceeding, Constellation claims that utilities' opposition to co-location is an anti-competitive ploy to capitalize on their state-granted monopolies.⁷⁹ The company alleges that co-location arrangements at two of its nuclear plants are "being held hostage by one or two monopoly utilities . . . [that] have taken the law into their own hands, and are unilaterally blocking co-location projects unless the future data center customers accede to utility demands to take [] transmission services . . . from the utility and sign up for retail distribution services."⁸⁰ Utilities may be trying to delay Constellation's projects until FERC provides clear guidance on co-location arrangements, including whether data centers and nuclear plants will pay any transmission charges.⁸¹

Even if FERC sets new rules the two sides are likely to continue squabbling about the details. With billions of dollars on the line, each side might have an incentive to litigate, which would add risk to co-location schemes.

III. Recommendations for State Regulators and Legislators: Strategies for Protecting Consumers from Big Tech's Power Costs

Without systematic changes to prevailing utility ratemaking practices, the public faces significant risks that utilities will take advantage of opportunities to profit from new data centers by making major investments and then shifting costs to their captive ratepayers. The industry's current approaches of luring data centers with discounted contracts or lopsided tariffs are unsustainable.

We outline five recommendations for PUCs to better protect consumers from subsidizing Big Tech's data centers: A) establishing guidelines for reviewing special contracts, B) shifting new data centers from special contracts to tariffs, C) facilitating competition and the development of "energy parks" that are not connected to any utility-owned network, D) requiring utilities to provide more frequent demand forecasts, and E) allowing new data centers to take service only if they commit to flexible operations.

A. Establish Robust Guidelines for Reviewing Special Contracts

PUCs rarely reject proposed special contracts with data centers. As we discussed, many states' laws provide PUCs with broad discretion to approve special contracts, do not specify a particular standard of review, and even allow the PUC to approve a contract that shifts costs to other ratepayers. Given the unprecedented scale and pace of data center special contracts, PUCs should establish more rigorous guidelines for reviewing special contracts that are aimed at protecting consumers.

In Kentucky, the Public Service Commission must make several findings on the record before approving a special contract.⁸² Under the PSC's self-imposed guidelines, special contracts that include discounts are allowed only when the utility has excess generation capacity. The guidelines limit discounts to five years and no more than half the duration of the contract. The PSC must also find that the contract rate exceeds the utility's marginal costs to serve that customer and that the contract requires the customer to pay any of the utility's fixed costs associated with providing service to that customer.

Applying its guidelines, the PSC recently rejected a utility's proposed special contract with a cryptocurrency speculator because it found the contract did not shield consumers from the crypto venture's power costs.⁸³ The PSC was critical of the utility's projections about regional market and transmission prices and therefore did not find credible the utility's claim that the contract would cover the utility's cost to provide energy to the crypto speculator. Industrial

ratepayers, several environmental and local NGOs, and Kentucky's attorney general, acting on behalf of consumers, participated in the proceeding and criticized the proposed contract.

While the PSC's guidelines compel it to address vital consumer protection issues, the rule cannot force regulators to critically analyze the utilities' filing or prevent the PSC from merely rubber-stamping a utility's proposed special contract. Vigorous oversight cannot be mandated by law: it requires dedicated public servants. The effectiveness of any consumer protection guidelines depends on the people who implement it, including PUC staff that review utility proposals and the commissioners who make the ultimate decisions. Nonetheless, we believe that establishing guidelines that require regulators to make specific findings about a proposed special contract would improve upon the status quo.

B. Require New Data Centers to Take Service Under Tariffs

Special contracts are vehicles for shifting special interests' energy costs to consumers. Approved in confidential proceedings by PUCs facing political pressure to approve deals and often with no competing interests participating, special contracts allow utilities to take advantage of the subjectivity and complexity of their accounting practices to socialize energy-intensive customers' costs to the public. The existing guardrails that ostensibly allow regulators to police special contracts are not working to protect consumers.

Guided by their consumer-protection mandate, regulators should stop approving any special contracts and instead require utilities to serve data centers through tariffs that offer standard terms and conditions for all future data-center customers. Unlike a one-off special contract that provides each data center with unique terms and conditions, a tariff ensures that all data centers pay under the same terms and that the impact of new customers is addressed by considering the full picture of the utility's costs and revenue. This holistic and uniform approach ends the race-to-the-bottom competition that incentivizes utilities to attract customers by offering hidden discounts paid for by other ratepayers.

That said, standard tariffs are not a talisman for protecting consumers. As we have emphasized, cost allocation is an imprecise exercise that depends on myriad assumptions and projections. However, tariff proceedings and rate cases are more procedurally appropriate forums than a special contract case to consider and address cost-allocation issues. Unlike special contracts, tariffs are reviewed in open dockets that allow the public and interested parties to scrutinize proposals and understand long-term implications of proposed rates should they go into effect. Once approved, a data-center tariff can be revisited in subsequent rate cases where the utility proposes to increase rates and allocate

its costs among ratepayers, including data centers. All ratepayers will have an incentive to participate in those cases and offer evidence that challenge data centers' interests.

Several utilities have already been moving away from special contracts to tariffs. Recent and ongoing proceedings are highlighting issues that demand careful scrutiny, including whether to create new data-center-only tariffs and how to protect existing ratepayers from costs of new infrastructure needed to meet data centers' demands. We briefly canvas these issues.

A threshold issue is whether an existing utility tariff for energy-intensive ratepayers is appropriate for data centers or whether a new tariff is necessary to address issues that are unique to data centers. Ratepayer classes are generally defined by the similar costs that the utility incurs to serve members of that class. Data centers may, of course, oppose new tariffs that impose more expensive prices than they would pay if they took service under existing tariffs for energy-intensive ratepayers.

In Ohio, for instance, AEP proposed to create classes for new data centers and cryptocurrency speculators and require ratepayers in those classes to commit to higher upfront charges and for a longer period of time than other energy-intensive consumers.⁸⁴ To justify the new data center class, AEP argued that data centers' unique size at individual locations and in the aggregate, as well as uncertainty about their energy use over the long-term and minimal employment opportunities, distinguish data centers from other energy-intensive consumers.⁸⁵ Data center companies responded that AEP had "failed to justify its approach to exclusively target data centers" and claimed that the utilities' costs to serve data centers was no different from other energy-intensive consumers that operate around the clock.⁸⁶ As of February 2025, the Ohio PUC has yet to rule on AEP's proposal.

FERC addressed similar issues in August 2024 when a utility proposed a new ratepayer class for energy-intensive cryptocurrency operations. Like AEP, the utility claimed that significant but uncertain demand growth justified approval of the new rate class, and therefore higher upfront payment commitments and longer terms for this new customer class were appropriate.⁸⁷ According to the utility, crypto speculators can more easily relocate their operations as compared to other energy-intensive consumers, and this mobility amplifies the risk of stranded assets built for new crypto customers that quickly set up shop elsewhere. FERC rejected the proposal because it found that the utility had provided insufficient evidence that new crypto operations "pose a greater stranded asset risk than other loads of similar size."⁸⁸ FERC's finding does not foreclose a utility from creating a crypto or data center ratepayer class, but instead signals that FERC will demand more persuasive evidence to justify approval of a new class.

State legislatures could remove any evidentiary hurdles by requiring large data centers to be in their own ratepayer class. With large data centers in their own class, regulators could more easily understand the effects data centers have on other ratepayers. For instance, parties might introduce evidence in a rate case showing how various cost allocation methods that raise costs for data centers would lower costs for other ratepayers. To avoid any claims of undue discrimination, the new rate class might include any new consumer above a specified capacity threshold that, as a practical matter, would likely capture only data centers.

Separating large data centers from other ratepayers could facilitate more protective cost allocation methods that better isolate data center costs from other ratepayers. Again, state legislatures might have a role to play. In Virginia, a bill proposed in January 2025 would require state regulators to determine whether cost allocation methods “unreasonably subsidize” data centers and to minimize or eliminate any such subsidies.⁸⁹ Such clear language would provide the PUC with guidance as it balances its obligations to protect ratepayers and facilitate growth in the state. In addition, it would force PUCs to revisit decades-old methods for dividing FERC-regulated transmission costs, as we discuss above.

As data centers shift to new tariffs, the largest potential cost shift in many states could be from the costs of new power plants built to meet data center growth. In most states, utilities are the dominant generation owners and can earn a PUC-set rate of return that they collect from ratepayers on their investments in new power plants. In general, utility expenses on new power plants are spread among ratepayer classes under the theory that all ratepayers benefit from the utility’s power plants. But the staggering power demands of data centers defy this assumption. Recent tariff proceedings highlight that many utilities are proposing schemes that are not adequately shielding ratepayers from the costs of new generation for data center growth.

In Indiana, the utility Indiana Michigan Power expects new data centers to increase the peak demand on its system from 2,800 to 7,000 megawatts.⁹⁰ To facilitate this growth, the utility proposed to create special terms for new customers that demand at least 150 megawatts of power, a threshold that in practice limits their applicability to new data centers.⁹¹ Like AEP Ohio’s proposal, the updated tariff would require a new data center to commit to paying 90 percent of the utility’s costs of new generation and transmission capacity needed to meet the data center’s demand.⁹² This 90 percent capacity payment and the tariff’s twenty-year term, according to the utility, would “provide reasonable assurance” that data centers’ payments to the utility “will reasonably align with the cost of the significant investments and financial commitments the Company will make to provide service.”⁹³

Consumer advocates generally supported the utility's efforts to insulate ratepayers from data centers' energy costs but argued that the proposed terms were "insufficient for protecting existing customers from large potential cost shifts in the event of the closure" of a large data center.⁹⁴ One of their solutions was to "firewall" the costs of new power plants built to meet data center growth from other ratepayers by requiring the utility to separately procure or build generation for data centers, and then allocating all costs solely to data centers.⁹⁵ Consumer advocates also urged regulators to require other modifications related to contract termination and other provisions to protect ratepayers from stranded costs if data center growth failed to materialize or decreased following an initial spike.⁹⁶

Data center companies argued the other side, claiming that the terms were too onerous and benefited the utility shareholders who "would be shielded from business risk, while reaping regulated returns on large potentially more risky expansion of rate base" that would be backed by data centers.⁹⁷ Amazon observed that the utility's proposed twenty-year term is based on the ordinary approach to cost recovery of utility capital investments. But instead of the utility building its own plants and earning a return on them, Amazon claimed that the utility could more efficiently support data center growth through short-term contracts with non-utility generators or purchases via PJM's regional markets.⁹⁸ Amazon argued that rather than "imposing virtually all risks" associated with power plant development on data centers and reaping all of the profits for itself, the utility should instead share the risks of infrastructure development with new data centers.⁹⁹

The Indiana proceeding highlights how utility ownership of generation can exacerbate cost shifts that benefit utility shareholders. The traditional utility business model of decades-long cost recovery of new utility-owned power plants through consumer rates is not designed to address a near-term tripling of a utility's demand due to just a few giant energy-guzzling warehouses. While "firewalling" data centers' power plant costs from other ratepayers is a viable approach, regulators must ensure that utility proposals actually protect consumers.

Under its "Clean Transition Tariff," Nevada Energy claims to insulate other ratepayers from data centers' energy generation costs by contracting with new clean energy resources and then passing those contract costs directly to a specific data center or other customer. In theory, this arrangement could isolate generation costs, but public utility staff and other intervenors concluded that the new tariff would not actually firewall data centers' generation costs from other ratepayers.¹⁰⁰ They found that complex interactions between the new tariff's proposed pricing structure and existing tariffs would shift costs to other ratepayers. For instance, PUC staff focused on the utility's proposal to account for the revenue it would have earned if the data center took service under a standard tariff and then charge other

ratepayers for a portion of its “lost” revenue.¹⁰¹ In February 2025, the utility agreed with intervenors to modify its proposal and defer consideration of some of these complicated cost allocation issues.¹⁰²

A better option for protecting ratepayers from power plant costs would be to allow data centers to purchase energy directly from non-utility retailers but still pay the utility for delivery service. Several states allow for such retail competition for energy-intensive consumers. To even further isolate data center energy costs, regulators could cut the cord entirely between the utility and data centers. Off-the-grid energy parks or energy parks that only export energy to the utility could completely insulate ratepayers from data centers’ energy costs.

C. Amend State Law to Require Retail Competition and Allow for Energy Parks

Competition can protect consumers from utility market power and insulate ratepayers from cost shifts. Starting in the 1970s, a few states began to allow limited competition for electricity service to certain energy-intensive consumers.¹⁰³ In the 1990s, about a dozen states permitted all ratepayers to shop for power supply while continuing to require them to pay state-regulated rates for utility-provided delivery service. Additional states allowed energy-intensive consumers to similarly choose a power supplier. To protect ratepayers, states could require new data centers to procure power through competitive processes rather than confining them to utility-supplied power. States could go further and allow or require new data centers to isolate entirely from the utility-owned network by creating new energy parks.

A mandate that new data centers procure power from non-utility suppliers would protect ratepayers from short-term costs and long-term risks. Requiring the data center to contract with a competitive supplier rather than with the utility would ensure that all stranded costs associated with the generation are allocated between the data center and its supplier. In addition, isolating the utility from the deal would obviate the need for the type of complex energy price calculations, integral to Nevada Energy’s proposal, that link the data center’s power price to the costs of the utility’s legacy assets.

The costs of utility-built power plants for data centers could be astronomical. In the Indiana proceeding discussed in the previous section, the utility’s own estimates revealed that if it met data center demand with self-built plants it could spend as much as \$17 billion on new power plants over the next several years.¹⁰⁴ The utility’s proposal to require data centers to commit to paying 90 percent of the infrastructure costs over a twenty-year period would

improve upon the status quo but would not completely isolate those costs from other ratepayers, particularly if data center demand did not meet the utility's forecasts.

Even with a state prohibition on new utility power plants for meeting data center demand, ratepayers could still face higher bills from cost shifts. A data center procuring energy from the market would still pay utility-imposed delivery charges that could obscure discounts for data centers or include various other cost shifts. Islanding the data center and its power supply from the utility-owned system is a sure-fire approach for protecting ratepayers.

An energy park, according to a recent paper by Energy Innovation, "combines generation assets, complementary resources like storage, and connected customers."¹⁰⁵ Unlike typical behind-the-meter arrangements where a customer installs some on-site generation to complement utility-delivered power, an energy park would provide sufficient power for the connected customers' operations. This arrangement is "particularly compelling for large customers due to the cost advantages of sourcing electricity directly from the cheapest, cleanest sources and due to the challenges of connecting large capacities to the existing grid."¹⁰⁶ Avoiding the protracted utility-run interconnection processes would be a benefit for Big Tech companies who tend to move faster than the lumbering utility industry.¹⁰⁷

A fool-proof way to insulate utility ratepayers from data center energy costs is to isolate a data center energy park from the utility-owned network. Isolation may be difficult, however, as an interconnected energy park could be more financially attractive to developers, even if it is only able to export power to the transmission system and unable to import utility-delivered power.¹⁰⁸ Connecting an energy park would require a utility-run interconnection process and would likely lead to the utility imposing transmission charges on the energy park. While transmission charges associated with an export-only energy park could facilitate cost shifts, they are likely to be much smaller than those embedded in special contracts and other arrangements for serving data centers with utility-delivered power that we have outlined in this paper.

Both competitive generation and energy park development face the same legal obstacle: state protection of utility monopolies. Under many states' laws, an entity that delivers or sells power to another entity is a "public utility." For instance, if a generation company owns the park's generation assets and Big Tech company owns the data center, the generation company would be regulated as a public utility. This designation could doom the project. States typically prohibit competition for electric service and regulators and courts might enforce the state's monopoly protections by prohibiting a multi-owner energy park located within the territory assigned to the incumbent utility.¹⁰⁹ Even if a state allows the energy

park to move forward as a public utility, the PUC may be compelled to regulate its rates and terms of service in a way that render the project unviable.

One potential workaround is to locate an energy park outside a for-profit utility's service territory. But states' laws may nonetheless impose obstacles. In Georgia, for instance, state law allows a new energy-intensive consumer located outside existing utility service territories to choose a supplier but limits the premises to a single customer.¹¹⁰ An energy park in Georgia could therefore include only one data center owner. Energy parks might also be able to locate within the service territory of a municipal or cooperative utility. The service territories of these non-profit entities may not be protected by state law, or they may not be financially motivated to defend their monopolies and might instead welcome an energy park's investment in their communities.¹¹¹ That said, some non-profit utilities may regard an energy park as an infringement on their monopolies.¹¹²

State legislatures could amend anachronistic laws that prevent energy park development and block data centers taking utility service from procuring non-utility generation. To avoid interminable utility complaints that competition harms consumers,¹¹³ laws could be tailored to apply only to data centers or other energy-intensive consumers that would otherwise require a utility to incur significant costs to procure power or build new generation.

D. Require Utilities to Disclose Data Center Forecasts

For competition to be effective, market participants need information about potential data centers' location and power demands. When utilities withhold that information, they prevent generators and other infrastructure and technology developers from offering data centers solutions that compete with the utility's offering. PUCs could require utilities to file monthly or quarterly load forecasts, which would reduce utilities' informational advantages and better enable other companies to offer solutions that would protect ratepayers from a utility's ability to shift data centers' costs to other consumers.

In the AEP Ohio proceeding, a trade association representing non-utility companies that sell electricity to consumers uncovered that AEP was withholding information. It documented that the utility's demand forecasts it filed in prior proceedings were inconsistent with its projections about data center growth it revealed to justify its data center tariff proposal.¹¹⁴ The trade association's analyst explained that by holding back information AEP "conferred a *de facto* competitive advantage to build transmission rather than allowing a market response from competitive merchant generation" to meet data center demand.¹¹⁵ The analyst also conjectured that AEP's concealment might directly harm ratepayers if it delayed

development of generation that might be needed to meet growing regional demand, which could lead to increased prices in PJM's capacity auction.¹¹⁶

PUCs can order utilities to provide demand projections more frequently and specify that utilities include new energy-intensive consumers at various stages of development. Utilities could also provide potential locations and demands of new energy-intensive consumers with enough specificity to be useful to market participants but sufficiently obscured to protect consumers' potentially confidential business information. Because many utilities have substantially increased their demand forecasts over the past year,¹¹⁷ new reporting rules would be well justified as a means of protecting consumers, enabling competition, and ensuring reliability.

E. Allow New Data Centers to Take Service Only if They Commit to Flexible Operations that Can Reduce System Costs

State regulators could require utilities to condition service to new data centers on a commitment to flexible operations. This approach could benefit all ratepayers by avoiding or reducing the need for expensive infrastructure that would otherwise be needed when a new data center increases the utility's maximum demand. A study by researchers at the Nicholas Institute for Energy, Environment & Sustainability estimates that 76 GW of data centers could connect to the system if utilities curtail energy delivery for just a few hours per year.¹¹⁸

As discussed above, utilities and RTOs plan power system expansion to provide sufficient capacity for meeting consumers' maximum energy demand, which usually occurs on the hottest and coldest days of the year. Because the system is planned for these extreme weather days, a large portion of a power system's generation and delivery infrastructure is underutilized for most of the year. If a data center commits to reducing its consumption of utility-supplied power during peak demand periods, utilities could deliver power to the data center without building new infrastructure.

To implement a flexibility mandate, PUCs could order utilities to modify their tariffs and classify data center loads as interruptible customers whose power can be turned off under specified circumstances. Similarly, regulators could also require utilities to modify their interconnection procedures to designate data centers as controllable loads that must reduce their consumption under certain conditions.¹¹⁹ These strategies could defer the immediate need for costly infrastructure upgrades to serve new data centers. Utilities, however, have historically been hostile to regulatory attempts to require measures that would defer or avoid the need for costly infrastructure upgrades that drive utilities' profits.

IV. Subsidies Hidden in Utility Rates Extract Value from the Public

Utility rates have always been a means of achieving economic and energy policy goals. By financing favored investments through utility rates, rather than through general government revenue, policymakers can avoid having to raise taxes and instead conceal public spending through complex utility rate increases. From the public's perspective, hiding subsidies in utility rates may be acceptable if the benefits of the favored investments exceed their costs. For data centers deals, however, utilities do not publicly demonstrate that ratepayers pay lower rates as a result of the contract. To the extent data center development offers other benefits, such as expanding the local economy or advancing national security interests, we argue that these secondary effects are either already accounted for through other policies or irrelevant to utility regulators.

The economic harm to ratepayers from data center discounts extends beyond the short-term bill increases that utilities are imposing on the public. We are concerned that meeting data center demand is delaying opportunities to initiate power sector reforms that would benefit all ratepayers. To power new data centers, utilities are proposing more of the same: spending capital on large central-station power plants and transmission reinforcements. These types of projects have been fueling utility profits for generations, but the power sector today can do so much more. Deploying advanced technologies and adopting new operational and planning practices could squeeze more value from existing utility systems, but these low-capital-cost solutions are not profitable for utilities and therefore not pursued.¹²⁰ By approving special contracts for data centers and tariffs that do protect ratepayers from Big Tech's energy costs, PUCs may be inadvertently fostering an alliance between utilities and Big Tech that could reinforce the industry's technological status quo.

A. Data Center Subsidies Fail Traditional Benefit-Cost Tests

When a utility spends money to supply a new data center, the data center should pay for those investments. However, if ratepayers ultimately benefit from new infrastructure needed for a data center, it may be reasonable for the utility to charge ratepayers a portion of the costs. The "beneficiary pays" principle, an analogue of the cost causation standard, justifies short-term bill increases when they are offset by longer term benefits that reduce ratepayers' bills. Just as consumers should pay costs that reflect a utility's cost to serve them, a utility may charge consumers for projects that ultimately lower their rates.

PUCs have applied the beneficiary pays approach in numerous contexts. For example, many states fund energy efficiency programs through utility rates. These programs directly benefit the ratepayers that make use of the program's discounts for energy audits, new appliances,

and other interventions that can reduce power use. All ratepayers are billed for these subsidies that flow directly to a handful of individual consumers that take advantage of these benefits. PUCs approve of this spending when programs ultimately lower peak system demand or otherwise reduce power system costs more than the costs of funding the efficiency program. We acknowledge, however, that these calculations are premised on assumptions and judgments and can be as imprecise as the cost allocation exercises we critique in this paper. The best regulators can do is conduct these analyses transparently, which allows for judicial review, limits the potential for arbitrary regulatory decisions, and provides a basis for changing the policy in response to new evidence.

In special contract proceedings, utilities and PUCs offer no such transparency about data center deals. Instead, billion-dollar contracts are proposed and approved without public accounting of the costs and benefits. Given the stakes and the incentives of the parties, the burden ought to be on utilities to prove publicly that ratepayers are benefiting from these deals, or at worst are being held harmless.

Ratepayers should not be saddled with costs due to data centers' purported strategic national importance. In January 2025, the Biden administration declared that AI is "a defining technology of our era" that has a "growing relevance to national security."¹²¹ "Building AI infrastructure in the United States on the time frame needed to ensure United States leadership over competitors," according to the Biden administration, will "prevent adversaries from gaining access to, and using, powerful future systems to the detriment of our military and national security."¹²² If this frightening scenario proves true — that AI will be a privately owned global weapon — it's not clear what it has to do with utility rates.

Data center proponents also tout the economic benefits of new development, but the public is already paying for local job growth through their taxes. Apart from discounted utility rates, many data centers separately receive generous state and local subsidies that governments rationalize based on the supposed economic and employment benefits of permitting new development. Several states, for instance, offer sales tax exemptions that allow data center companies to purchase computers, cooling equipment, and other components without paying state tax. In Virginia, the exemption saved data center companies nearly a billion dollars in 2023 alone.¹²³ Data centers may also benefit from one-off incentive packages. Mississippi is providing an Amazon data center with nearly \$300 million of workforce training and infrastructure upgrades.¹²⁴ Mississippi will also reimburse Amazon for 3.15 percent of the data center construction costs and provide tax exemptions that could be worth more than \$500 million. In lieu of taxes, Amazon will pay approximately \$200 million in fees to the county over five years.¹²⁵

B. Data Center Subsidies Interfere with Needed Power Sector Reforms

The power sector needs major upgrades. Investment in new high-voltage transmission is historically low,¹²⁶ despite an acute need for new power lines that can connect consumers to cheaper and cleaner sources of energy and improve network reliability.¹²⁷ With low interconnectivity, the utility industry is siloed into regional alliances that make little engineering or economic sense. Meanwhile, utilities have been sluggishly slow to adopt monitoring, communications, and computing technologies that can improve the performance of existing high-voltage networks.¹²⁸ At the local level, utilities are failing to unlock the potential of distributed energy resources to lower prices.¹²⁹

Data center growth provides utilities with an excuse to ignore these inefficiencies. Utilities don't have to innovate to supply Big Tech's warehouses and are instead offering to meet data center demand with transmission reinforcements and gas-fired power plants, which have been the industry's bread-and-butter for decades. Some utilities are even propping up their oldest and dirtiest power plants to meet data center demand.¹³⁰ Neither data centers nor regulators are challenging utilities to modernize their systems.

Power sector stagnation is the fault of utilities and the regulatory construct that incentivizes inefficient corporate decisions. Rate regulation enables excessive utility spending that crowds out cheaper alternative investments. Because they are monopolists, utilities do not face competition that might expose their inefficiencies. Regulated rates rarely punish utilities for inefficiencies or reward them for improving their operations through low-cost technologies. Ultimately, regulators must try to align utility performance with consumers' interests, but achieving this straightforward objective is dauntingly complex.

Data center growth now overwhelms many PUC agendas. By law, regulators must respond to utility proposals about rate increases, special contracts, infrastructure development, and other issues. Utilities' messaging to regulators and investors is that meeting data centers' growth targets is an urgent priority. The implication is that there's no time to act differently. With utilities' push for growth dominating their dockets, PUCs may find it even harder to reform inefficient utility practices and block unneeded investments. For ratepayers, beneficial projects will remain unfunded, and wasteful utility practices will persist.

As utilities wring profits from the public through special contract approvals, they may be developing a new alliance with Big Tech. Uniting utilities' influence-peddling experience with the deep pockets of Big Tech could further entrench utility control over the power sector. Utilities are already among the largest donors to state elected officials and have a century of experience navigating state legislatures and agencies to protect their monopoly control and

otherwise advance their interests. A long-term partnership to push the common interests of utilities and data centers at statehouses, PUCs, and other forums could undermine reform efforts and harm ratepayers.

While energy-intensive consumers typically have a financial incentive to participate in PUC proceedings and argue for their own self-interest by opposing wasteful utility spending, we are concerned that a different scenario may play out for data centers. If utilities' growth predictions are realized, some utilities will have invested billions of dollars to serve data centers that will consume *a majority of all power* delivered by the utility. Under this scenario, the utility will be dependent on its data center customers for revenue and will need to retain them in order to justify its prior and future expansion. To prevent data center departures and attract new data center customers, utilities might continue to offer discounted rates. Rather than acting as watchdogs in PUC proceedings, data center companies may instead focus on securing more discounts. Insulated by special contract deals and favorable tariffs with friendly utilities, data center companies would focus on defending their discounts rather than disciplining the utility's spending in rate cases.

Outside of formal proceedings, utility-Big Tech alliances could amplify pro-utility political messages. Utilities have a pecuniary interest in the laws that govern PUC decisionmaking and push for changes that benefit their bottom lines. Utilities formally lobby state legislators and also pursue an array of public relations strategies to secure favorable legislative and regulatory outcomes. Big Tech has the financial capacity to significantly increase the amount of money supporting of pro-utility bills and regulatory actions.

An alternative approach — which requires data centers to power themselves outside of the utility system — sets up a formidable counterweight to utilities' monopoly power. If Big Tech is forced to power itself, it might defend against utility efforts to limit competition and return to the pro-market advocacy that characterized the Big Tech's power-sector lobbying efforts prior to the ChatGPT-inspired AI boom.

Appendix A
Big Tech Companies and Data Center Developers Testifying that
Utility Prices Inform Where They Build New Facilities

- AEP Ohio Proposed Tariff Modifications, *supra* note 2, Motion to Intervene and Memorandum in Support of Sidecat, an Affiliate of Meta (Jun. 10, 2024) (“The applicable electricity rates and corresponding electric service tariffs for AEP Ohio will be a significant consideration for Meta when evaluating possible sites for new facilities, expansions at existing facilities, and otherwise operating its data center assets.”).
- AEP Ohio Proposed Tariff Modifications, Direct Testimony of Brendon J. Baatz in Opposition of the Second Joint Stipulation and Recommendation, at 4 (Nov. 8, 2024) (“the terms and conditions in Schedule DCT are far more restrictive and burdensome than those imposed by investor-owned utilities in other states, which could prompt some data center customers to consider investing outside of Ohio”).
- AEP Ohio Proposed Tariff Modifications, Second Supplemental Direct Testimony of Michael Fradette, on Behalf of Amazon Data Services, Inc., at 18 (Nov. 8, 2024) (“By rejecting a stipulation that unfairly discriminates against data centers, the Commission can help ensure that Ohio continues to be a leader in attracting investment from this vital industry.”).
- AEP Ohio Proposed Tariff Modifications, Motion to Intervene of Data Center Coalition, at 4 (May 24, 2024) (“AEP Ohio’s proposals, and potential proposals made by intervenors in the case, may have a significant impact on existing and planned data centers in AEP Ohio’s service territory.”).
- AEP Ohio Proposed Tariff Modifications, Direct Testimony of Brendon J. Baatz, at 11 (Oct. 18, 2024) (“If AEP Ohio’s proposal is adopted, it would create an unfavorable environment for data center development in the state, potentially causing companies to reconsider their investment plans.”).
- AEP Ohio Proposed Tariff Modifications, Direct Testimony of Kevin C. Higgins on behalf of The Data Center Coalition, at 7 (Oct. 18, 2024) (“If approved, the DCP tariff will adversely impact planned data center development in the Company’s service territory.”); *id.* at 11 (“At the same time, it is important that the Commission not take actions that would depress the growth of an important emerging industry by imposing unjust and discriminatory terms.”).
- Indiana Michigan Power Proposed Tariff Modification, *supra* note 15, Direct Testimony of Kevin C. Higgins on behalf of The Data Center Coalition, at 6 (Oct. 15, 2024) (“If

approved, the IP Tariff changes could adversely impact planned data center development in the Company's service territory.").

- Indiana Michigan Power Proposed Tariff Modification, Direct Testimony of Justin B. Farr on behalf of Google, at 23 (Oct. 15, 2024) ("Modifications . . . have the potential to limit opportunities for . . . the development of shared solutions that can provide significant benefit to I&M's system by removing the financial incentive for I&M to collaborate with its customers to pursue innovative solutions to support their growth.").
- Indiana Michigan Power Proposed Tariff Modification, Direct Testimony of Michael Fradette on behalf of Amazon Data Services, Inc., at 37 (Oct. 15, 2024) ("The proposed [tariff] is not reasonable and in fact has a negative impact on Amazon's view for future investment actions within I&M's service territory. I&M has offered no reasonable justification for revising Tariff I.P. as proposed.").
- Contracts for Provision of Electric Service to a New Large Customer's Minnesota Data Center Project, Minn. Pub. Util. Comm'n Docket No. 22-572, Petition, at 28 ("The customer has made clear that the CRR Rate is critically important to its decision to select a site in Minnesota for its new data center. Without the CRR Rate, the economic feasibility of this new data center would be jeopardized.").
- In re Application of Pub. Serv. Co. of Colorado for Approval of a Non-Standard EDR Contract, Pub. Util. Comm'n of Colorado Proceeding No. 23A-0330E, Direct Testimony & Attachment of Travis Wright on behalf of Quality Technology Services, at 8 (Jun. 23, 2023) ("QTS selects its new locations extremely carefully. Electricity is one of the major costs to operating a data center, so the low EDR rate provided by Public Service, and the term of the EDR agreement, is a critical factor in determining to locate in Aurora."); *id.* at 10–11 ("Given that approximately 40 percent of the Aurora QTS Campus's operational expense will be attributable to utilities, with electric being the largest component, the cost per kWh can easily make or break a project, or drive QTS or its customers to invest resources elsewhere. The EDR ESA that we have negotiated with Public Service and are requesting approval of in this Proceeding, is a critical component of our business model for the Aurora QTS Campus."); *id.* at 16 ("Was the cost of electricity a critical consideration for QTS in deciding where to site its new operations? Yes. 40 percent of the operational cost of a data center is electricity, and this will usually be the largest line item on the budget. Additionally, this cost will continue for 40 years, and will scale the business. In contrast, real estate and development costs are one-time, up-front expenditures that are watered down as the

volume of business increases. The largest and fastest growing operations in our portfolio are in markets where electricity costs are competitive.”).

- In re Application of Ohio Power Company and New Albany Data Center, LLC for Approval of a Reasonable Arrangement, Pub. Util. Comm’n of Ohio Case No. 23-0891-EL-AEC, Joint Application, at 7 (Sep. 28, 2023) (“Without this reasonable arrangement, NADC could construct its own dedicated substation and take lower-cost service under AEP Ohio’s transmission voltage tariff – to the extent it would decide to develop its facilities in AEP Ohio’s service territory.”).
- Application of Nevada Power Company for Approval of an Energy Supply Agreement with Lumen Group, Pub. Util. Comm’n of Nev. Docket No. 19-12017, Application, Attachment A: Long Term Energy Supply Agreement White Paper, at 17 (Dec. 19, 2019) (“The ESA provides Google with important benefits . . . the blended rate provided for in the ESA is cost-effective and competitively priced compared to other available options, the fixed-price nature of the agreement provides Google with important cost-certainty into its energy expenditures . . .”).

Endnotes

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¹ See, e.g., JOHN D. WILSON, ZACH ZIMMERMAN & ROB GRAMLICH, STRATEGIC INDUSTRIES SURGING: DRIVING US POWER DEMAND 8 (Grid Strategies, Dec. 2024) [hereinafter Grid Strategies Report]; Alastair Green et al., [How Data Centers and the Energy Sector Can Sate AI's Hunger for Power](#), MCKINSEY & Co., ("Much of data center growth — about 70 percent — is expected to be fulfilled directed or indirectly (via cloud services, for instance) by hyperscalers by 2030"); EPRI, POWERING INTELLIGENCE: ANALYZING ARTIFICIAL INTELLIGENCE & DATA CENTER ENERGY CONSUMPTION 7 (May 2024) [hereinafter Powering Intelligence]; Jennifer Hiller & Katherine Blunt, [Inside the Audacious Plan to Reopen Three Mile Island's Nuclear Plant](#), WALL ST. J. (Nov. 10, 2024), ("Analysts at Jefferies estimate Microsoft will pay between \$110 and \$115 per megawatt hour of electricity").

² See, e.g., In re Application of Ohio Power Company for New Tariffs Related to Data Centers, Pub. Util. Comm'n of Ohio Case No. 24-508-EL-ATA [hereinafter AEP Ohio Proposed Tariff Modifications], Direct Testimony of Kevin C. Higgins on behalf of The Data Center Coalition, at 7 ("If approved, the [proposed] tariff will adversely impact planned data center development in the Company's service territory."); *id.* at 11 ("At the same time, it is important that the Commission not take actions that would depress the growth of an important emerging industry by imposing unjust and discriminatory terms."). See Appendix A for additional evidence.

³ See, e.g., Rich Miller, [Skybox Plans 300-Megawatt Campus South of Dallas](#), DATA CENTER FRONTIER (Nov. 20, 2023); City of Cleveland, [Office of Sustainability & Climate Justice](#) (noting that the city has a 300-megawatt system).

⁴ Palo Verde is the largest nuclear power station in the U.S. Its three reactors produce approximately 3.3 gigawatts. Meta announced a two-gigawatt data center development in December 2024. See Dan Swinhoe & Zachary Skidmore, [Meta Announces 4 Million Square Foot, 2 GW Louisiana Data Center Campus](#), DATA CENTER DYNAMICS (Sep. 5, 2024).

⁵ See generally Powering Intelligence; Alastair Green et al., [How Data Centers and the Energy Sector Can Sate AI's Hunger for Power](#), MCKINSEY & Co.

⁶ See, e.g., Grid Strategies Report ("[A]nnual peak demand growth will average 3% per year over the next five years. While 3% growth may seem small to some, it would mean six times the planning and construction of new generation and transmission capacity.").

⁷ See FED. ENERGY REG. COMM'N, SUMMER ENERGY MARKET & ELECTRIC RELIABILITY ASSESSMENT 46 (May 23, 2024) (showing 19 GW actual demand in 2023); Newmark, 2023 U.S. DATA CENTER MARKET OVERVIEW & MARKET CLUSTERS 7 (Jan. 2024) (projecting 35 GW in 2030); [AI is Poised to Drive 160% Increase in Data Center Power Demand](#), Goldman Sachs (May 14, 2024).

⁸ See Grid Strategies Report, at 12.

⁹ See Georgia Power Company, Georgia Pub. Serv. Comm'n Docket No. 56002, [Budget 2025: Load and Energy Forecast 2025 to 2044](#) (Jan. 31, 2025); Drew Kann and Zachary Hansen, *Data Centers Use Lots of Energy: Georgia Lawmakers Might Make Them Pay More*, THE ATLANTA JOURNAL CONSTITUTION (Feb. 13, 2025) (stating that Georgia Power executives stated that 80 percent of the company's forecasted electricity demand growth is due to data centers).

¹⁰ Press Release, [Oncor Electric Delivery Company, Oncor Reports Third Quarter 2024 Results](#) (Nov. 6, 2024),.

¹¹ Robert Walton, [ERCOT Successfully Navigates Heat Wave, New Peak Demand Record](#), UTILITY DIVE (Aug. 26, 2024).

¹² See Ethan Howland, [AEP Faces 15 GW of New Load, Driven by Amazon, Google, Other Data Centers: Interim CEO Fowke](#), UTILITY DIVE (May 1, 2024); American Electric Power, [4th Quarter Earnings Presentation](#) (Feb. 13, 2025).

¹³ See, e.g., In re Application of Ohio Power Company for New Tariffs Related to Data Centers, Pub. Util. Comm'n of Ohio Case No. 24-508-EL-ATA [hereinafter AEP Ohio Proposed Tariff Modifications], Direct Testimony of Matthew S. McKenzie on Behalf of Ohio Power Company [hereinafter Ohio Power Company Testimony], at 2 (May 13, 2024).

¹⁴ Indeed, investors are taking note. The authors have on file numerous reports from utility stock analysts that tout the potential of data center growth. Utilities' presentations to investors claim that data center growth will drive future earnings. See, e.g., AEP 4th Quarter Earnings Presentation, *supra* note 13, at 13 (stating that "Load Growth Supports Financial Strength" and noting it is being driven by data centers).

¹⁵ See, e.g., *In re Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Tariff*, Indiana Util. Reg. Comm'n Cause No. 46097 [hereinafter *Indiana Michigan Power Proposed Tariff Modifications*], Testimony of Indiana Consumer Advocates, at 4 (Oct. 15, 2024) ("There has been a significant lack of transparency with these new loads . . . For example, with respect to new large loads coming to I&M's service territory, Google and Microsoft refused to answer CAC data requests about their anticipated load and electricity consumption, and Microsoft also refused to identify its forecasted load factor. CAC counsel reached out to counsel to these parties and requested to execute a non-disclosure agreement with each respective company so that CAC could obtain this pertinent information, but thus far, we have not received a proposed non-disclosure agreement or the confidential information."). Most of the figures in the Georgia Power filing cited at note 9 are redacted.

¹⁶ See, e.g., AEP Ohio Proposed Tariff Modifications, Ohio Power Company Testimony, *supra* note 13, at 2 ("Currently, AEP Ohio has limited ability to distinguish customers who are merely speculating on potential data center investments from customers who are willing to make long-term financial commitments to data center investments.") (original emphasis); *Large Loads Co-Located at General Facilities Technical Conference*, FERC Docket No. AD24-11-000, Transcript, at 26 (Aubrey Johnson, Vice-President, Systems & Resource Planning for the Midcontinent Independent System Operator explaining that "in many cases, these data centers are showing up in multiple places, so I have many members submitting loads that are all the same. So how do we have more clarity . . . to understand what the actual true load is?").

¹⁷ See *generally* Powering Intelligence, at 7.

¹⁸ See, e.g., David Uberti, [AI Rout Sends Independent Power Stocks Stumbling](#), WALL ST. J. (Jan. 27, 2025), ("DeepSeek's efficient approach have 'created panic among investors who question the sustainability of US data center and AI investments,' Guggenheim analysts wrote in a note"); JONATHAN KOOMEY, TANYA DAS & ZACHARY SCHMIDT, *ELECTRICITY DEMAND GROWTH AND DATA CENTERS: A GUIDE FOR THE PERPLEXED* (Bipartisan Policy Center & Koomey Analytics, Feb. 2025).

¹⁹ The Grainger College of Engineering, [Why DeepSeek Could be Good News for Energy Consumption](#), (Feb. 6, 2025); James O'Donnell, [DeepSeek Might Not be Such Good News for Energy After All](#), MIT TECH. REVIEW (Jan. 31, 2025).

²⁰ See Deepa Seetharaman and Tom Dotan, [Tech Leaders Pledge Up to \\$500 Billion in AI Investment in the U.S.](#), WALL ST. J. (Jan. 21, 2025).

²¹ Jordan Novet, [Microsoft Expects to Spend \\$80 Billion on AI-Enabled Data Centers in Fiscal 2025](#), CNBC (Jan. 3, 2025).

²² Press Release, State of Ohio, [Governor DeWine Announces \\$10 Billion Investment Plan from Amazon Web Services in Greater Ohio](#) (Dec. 16, 2024).

²³ Dan Swinhoe & Zachary Skidmore, [Meta Announces 4 Million Sq Ft, 2 GW Louisiana Data Center](#), DATA CENTER DYNAMICS (Dec. 5, 2024).

²⁴ See *generally* Aneil Kovvali & Joshua C. Macey, *Hidden Value Transfers in Public Utilities*, 171 PENN. L. REV. 2129 (2023).

²⁵ KEN COSTELLO, *ALTERNATIVE RATE MECHANISMS & THEIR COMPATIBILITY WITH STATE UTILITY COMMISSION OBJECTIVES*, NATIONAL REGULATORY RESEARCH INSTITUTE 2 (Apr. 2014).

²⁶ See U.S. Energy Information Administration, *Electric Power Monthly*, [Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector](#) (showing average residential, commercial, and industrial rates in each state).

²⁷ *Alabama Elec. Co-op., Inc. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982).

²⁸ *Co. Interstate Gas Co. v. Fed. Power Comm'n*, 324 U.S. 581, 590 (1945).

²⁹ JAMES C. BONBRIGHT, *PRINCIPLES OF PUBLIC UTILITY RATES* 338 (1961).

³⁰ See, e.g., *Off. of Consumer Counsel v. Dep't of Pub. Util. Control et al.*, 905 A.2d 1, 6 (Conn. 2006) ("In the specialized context of a rate case, the court may not substitute its own balance of the regulatory considerations for that of the agency, and must assure itself that the [department] has given consideration of the factors expressed in [the statute]."); *Iowa-Ill. Gas & Elec. Co. v. Ill. Com. Comm'n*, 19 Ill. 2d 436, 442 (Ill. 1960) (explaining that deference to the Commission is "especially appropriate in the area of fixing rates"); *Farmland Ind., Inc. v. Kan. Corp. Comm'n*, 37 P.3d 640, 650 (Kan. App. 2001) (providing that the Kansans Corporation Commission "has broad discretion in making decisions in rate design types of issues"); *Ohio Consumers' Counsel v. Pub. Util. Comm'n*, 926 N.E.2d 261, 266 (Ohio 2010) ("The lack of a governing statute telling the commission how it must design rates vests the commission with broad discretion in this area.").

³¹ See *2024 FERC Rep. on Enforcement*, FERC Docket No. AD07-13-018, at 51 (Nov. 21, 2024) ("Most audits find that public utilities recorded non-operating expenses and functional operating and maintenance expenses

in [Administrative and General] expense accounts, leading to inappropriate inclusion of such costs in revenue requirements produced by their formula rates”); see also *infra* note 34.

³² *FirstEnergy Corp.*, FERC Docket No. FA19-1-000, Audit Report, at 48 (Feb. 4, 2022).

³³ *Id.* at 16.

³⁴ See, e.g., *Application of Southern California Gas Company for Authority to Update its Gas Revenue Requirement and Bas Rates*, California Pub. Util. Comm’n Application 22-05-015, Decision 24-12-074, at 7 (Dec. 19, 2024) (“The decision [to use one-way balancing accounts] highlights a pattern of misclassification of costs at Sempra Utilities, where the company has charged ratepayers for lobbying, political activities, and expenses related to outside legal firms. These costs have been improperly booked as above-the-line expenses when forecasting future costs.”); *Order Instituting Rulemaking*, California Pub. Util. Comm’n Rulemaking 13-11-005, Decision 22-04-034 (Apr. 7, 2022) (“As an experienced utility, SoCalGas should have known that its billing of lobbying against reach codes implicates several basic legal principles that are central to its duties to the Commission and to customers . . . Thus, aside from billing ratepayers for lobbying contrary to the intent of the Commission, SoCalGas appears on the face of the record to have misled staff about the direction of its lobbying....”). See also 2024 FERC Rep. on Enforcement, FERC Docket No. AD07-13-018, at 58 (Nov. 21, 2024) (summarizing that FERC audits revealed “improper application of merger-related costs; lobbying, charitable donation, membership dues, and employment discrimination settlement costs; improper labor overhead capitalization rates....”).

³⁵ Costello, *supra* note 25, at 44. See also *Investigation into the Reasonableness of Rates & Charges of PacifiCorp*, Utah Pub. Serv. Comm’n Docket No. 99-035-10, 2000 WL 873337 (2000) (“[E]ach class of service does not pay precisely its ‘share’ of costs. This is true, for example, of the large customer groups, or special contract customers, according to some views of allocations.”).

³⁶ See, e.g., MINN. STAT. § 216B.162, subd.7 (2024); COLO. REV. STAT. ANN. § 40-3-104.3 (West 2018); MICH. COMP. LAWS § 460.6a(3).

³⁷ KAN. STAT. ANN. § 66-101i.

³⁸ See MISS. CODE ANN. § 77-3-271(3) (“A public utility may enter into a large customer supply and service agreement with a customer, which may include terms and pricing for electric service without reference to the rates or other conditions that may be established or fixed under Title 77, Chapter 3, Article 1, Mississippi Code of 1972. No approval by the commission of such agreement shall be required. With respect to such an agreement...the agreement, including any pricing or charges for electric service, shall not be subject to alteration or other modification or cancelation by the commission, for the entire term of the agreement....”).

³⁹ See Appendix A.

⁴⁰ See, e.g., *Application of El Paso Electric Company for an Economic Development Rate Rider for a New Data Center*, Pub. Util. Comm’n Texas Docket No. 56903, Order No. 1 (Aug. 2, 2024) (issuing standard protective order with no analysis); *Petition of Duke Energy Indiana for Approval of a Special Retail Electric Service Agreement*, Indiana Util. Reg. Comm’n Cause No. 45975, Order (Nov. 20, 2023) (granting Duke Energy’s motion for confidential treatment); *In re Cheyenne Light, Fuel & Power Co. Petition for Confidential Treatment of a Contract with Mineone Wyoming Data Center LLC*, Wyoming Pub. Serv. Comm’n Docket No. 20003-238-EK-24 (Record No. 17600), Letter Order (Oct. 9, 2024) (authorizing confidential treatment); *In re Xcel Energy’s Petition for Approval of Contracts for Provision of Service to a New Large Customer’s Minnesota Data Center Project*, Minn. Pub. Util. Comm’n Docket No. E-002/M-22-572, Order (excising significant portions of the proposed service agreement and staff analysis because it is a “highly confidential trade secret”); *Tariff Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC*, Kentucky Pub. Serv. Comm’n Case No. 2022-00387, Order (Dec. 4, 2024), at 3 (granting confidential treatment for utility filing and providing that the information “shall not be placed in the public record or made available for public inspection for five years or until further order[ed]”).

⁴¹ See *id.*; see also Daniel Dassow, [University of Tennessee Professor Sues TVA for Records of Incentives to Bitcoin Miners](#), KNOXVILLE NEWS SENTINEL (Oct. 29, 2024) (explaining how there was no information about the incentives that TVA gave a cryptocurrency company to build within its footprint, but that the company used 9.4 percent of all Knoxville Utilities Board electricity in 2023 while employing just thirty people).

⁴² See Costello, *supra* note 25, at 21.

⁴³ See Peter Lazare, *Special Contracts and the Ratemaking Process*, 10 ELEC. J. 67, 68–70 (1997) (quoting a Commonwealth Edison filing that argues long-run costs are appropriate for rate cases and short-term costs are appropriate for special contract proceedings and explaining the implications of using different metrics).

⁴⁴ See, e.g., *In re Application of Ohio Power Company and New Albany Data Center, LLC for Approval of a Reasonable Arrangement*, Pub. Util. Comm’n of Ohio Case No. 23-0891-EL-AEC, Order Approving the Application with Modification (“The proposed arrangement meets the burden of proof for obtaining a

reasonable arrangement under Ohio Adm. Code Chapter 4901:1-38. Furthermore, we find that the proposed arrangement, as modified by Staff, is reasonable and should be approved.”). Occasionally, a state PUC applying its public interest standard will gesture at a utility’s static marginal cost analysis or no-harm analysis for analytical support. See, e.g., *Petition of Duke Energy Indiana for Approval of a Special Retail Electric Service Agreement*, Indiana Util. Reg. Comm’n Cause No. 45975, Order of the Commission (Apr. 24, 2024) (“In making such a determination [that the proposed agreement satisfies Indiana Code], two considerations are important: whether the rates negotiated between the utility and its customer are sufficient for the utility to cover the incremental cost of providing the service to the customer and still make some contribution to the utility’s recovery of its fixed costs, and whether the utility has sufficient capacity to meet the customer’s needs. As explained by [Duke Energy’s Vice President of Rates and Regulatory Strategy], the Agreement requires that Customer cover the incremental costs of providing service to it, as well as contributing to Petitioner’s recovery of fixed costs...Based on the evidence of record, we find and conclude that the terms and conditions contemplated in the Agreement are just and reasonable...Therefore, we find that the Agreement is in the public interest and is, therefore, approved....”); *In re Idaho Power Company’s Application for Approval of a Special Contract and Tariff Schedule 33 to Provide Electric Service to Brisbie, LLC’s Data Center Facility*, Idaho Pub. Util. Comm’n Case No. IPC-E-21-42, Order No. 35958 (“Commission Discussion and Findings: The Commission has jurisdiction over this matter under *Idaho Code* §§ 61-501, -502, and -503...We have reviewed the record in this case and find the Company’s August 30, 2023, Filing including an amended ESA, revised Schedule 33, and additional modifications is consistent with the Commission’s directive in Order No. 3577.”).

⁴⁵ See *Duke Energy Carolinas, LLC v. NTE Carolinas II, LLC*, 111 F.4th 337, 344–46 (4th Cir. 2024).

⁴⁶ *Id.* at 347.

⁴⁷ *Id.* at 349.

⁴⁸ See Appendix A.

⁴⁹ See generally Kovvali & Macey, *supra* note 24.

⁵⁰ Cross-Subsidization Restrictions on Affiliate Transactions, 73 Fed. Reg. 11,013 (2008) (codified at 18 C.F.R. pt. 35).

⁵¹ See, e.g., *Nantahala Power & Light Co. v. FERC*, 476 U.S. 953 (1986).

⁵² See, e.g., *Nat’l Ass’n of Reg. Util. Comm’rs v. FERC*, 475 F.3d 1227, 1285 (D.C. Cir. 2007); *Entergy Services, Inc. v. FERC*, 319 F.3d 536 (D.C. Cir. 2003); *South Carolina Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

⁵³ PJM, [PJM Board of Managers Approves Critical Grid Upgrades](#), PJM INSIDE LINES (Dec. 11, 2023).

⁵⁴ Sami Abdulsalam, Senior Manager, PJM Transmission Planning, [Reliability Analysis Update at Transmission Expansion Advisory Committee Meeting](#) (Dec. 5, 2023). See also *PJM Revisions to Incorporate Cost Responsibility Assignments for Regional Transmission Expansion Plan Baseline Upgrades*, FERC Docket No. ER24-843, Protest and Comments of Maryland Office of People’s Counsel (Feb. 9, 2024) [hereinafter Maryland People’s Counsel Protest].

⁵⁵ See generally *PJM Interconnection*, 187 FERC ¶ 61,012 at P 6 (2024); Maryland People’s Counsel Protest, Affidavit of Ron Nelson, at 5.

⁵⁶ See Maryland People’s Counsel Protest, Affidavit of Ron Nelson, at 5.

⁵⁷ See *Delmarva Power & Light Co. Modification of Retail Transmission Rates*, Maryland Pub. Serv. Comm’n Case No. 8890, Revised Tariff, Attachment E (Jul. 2, 2024) (allocating 68 percent of transmission costs to residential customers); *Potomac Electric Power Co. Modification of Retail Transmission Rates*, Maryland Pub. Serv. Comm’n Case No. 8890, Revised Tariff, Attachment F (Jul. 2, 2024) (allocating 53 percent of transmission costs to residential customers); *Baltimore Gas & Elec. Co. Updated Market-Priced Service Rates, Administrative Charges, and Retail Transmission Rates under Rider 1*, Maryland Pub. Serv. Comm’n Case Nos. 9056/9064, Attachment 2: Development of the Retail Transmission Rates (Apr. 30, 2024) (allocating 78 percent of transmission costs to residential customers).

⁵⁸ *Application of Virginia Electric and Power Co.*, Virginia Corp. Comm’n. Case No. PUR-2021-00102, Report of Chief Hearing Examiner Alexander F. Skirpan, Jr., at 9–10 (Jul. 14, 2021).

⁵⁹ The cost causation principle could require a shift from transmission rates based on average — or static marginal — costs, to dynamic marginal cost analyses. See *In re Application of Pub. Serv. Co. of Colorado for Approval of a Non-Standard EDR Contract*, Colorado Pub. Util. Comm’n Proceeding No. 23A-0330E, Commission Decision Denying Exceptions to Decision No. R24-0168 and Adopting Recommended Decision with Modifications, at 11–12 (May 15, 2024) (“[W]e emphasize that the Commission’s review of future Non-Standard EDR contracts must entail detailed examination of how the addition of large loads to the Public Service’s system may create a dynamic need for multi-billion new generation and transmission capacity investments that unpredictably show up with no meaningful notice to this Commission and may not be easily

captured in a static marginal cost analysis . . . To that end, the marginal cost analysis that Public Service applied to the EDR ESA with [the data center customer] may not be adequate in future proceedings where the Commission reviews a similar Non-Standard EDR contract especially in light of the rapidly evolving and dynamic interaction between rising demand and the potential costs of serving that growth.”).

⁶⁰ *Application of Virginia Electric Power*, Virginia Corp. Comm’n. Case No. PUR-2024-00135, Report of Hearing Examiner Bryan D. Stogdale, at 47 (Feb. 14, 2025).

⁶¹ *Application of Virginia Electric Power*, Virginia Corp. Comm’n. Case No. PUR-2024-00135, Report of Hearing Examiner Bryan D. Stogdale, at 23 (Feb. 14, 2025).

⁶² *Supra* note 58.

⁶³ See AEP Ohio Proposed Tariff Modifications, Ohio Power Company Testimony, at 18–20 (May 13, 2024).

⁶⁴ See AEP Ohio Proposed Tariff Modifications, Prepared Direct Testimony of Dennis W. Bethel on Behalf of Buckeye Power, Inc. and American Municipal Power [hereinafter Buckeye Power Comments], at 18–19 (Aug. 29, 2024).

⁶⁵ *Dayton Power & Light Co.*, 189 FERC ¶ 61,220 (2024).

⁶⁶ *Dayton Power & Light Co.*, FERC Docket No. ER25-192, Protest of the Office of the Ohio Consumers’ Counsel [hereinafter Protest of the Office of Ohio Consumers’ Counsel], at 4 (Nov. 13, 2024); *Dayton Power & Light Co.*, FERC Docket No. ER25-192, Limited Comments of Buckeye Power (Nov. 21, 2024).

⁶⁷ Protest of the Office of the Ohio Consumers’ Counsel at 5.

⁶⁸ *Dayton Power and Light Co.*, 189 FERC ¶ 61,220 at P 23 (2024).

⁶⁹ *PJM Interconnection and Virginia Electric and Power Company*, 169 FERC ¶ 61,041 (2019).

⁷⁰ See, e.g., Walker Orenstein, [Amazon Wants to Limit Review of 250 Diesel Generators at Its Minnesota Data Center](#), MINNESOTA STAR TRIBUNE (Feb. 17, 2025) (noting that Amazon wants to install 600 megawatts of on-site diesel-powered generators at its new data center).

⁷¹ *Constellation Energy Generation v. PJM*, FERC Docket No. EL25-20, Complaint Requesting Fast Track Processing of Constellation Energy Generation, LLC [hereinafter Constellation Complaint], at 20–21 (Nov. 22, 2024).

⁷² *Constellation Energy Generation v. PJM*, Docket No. EL25-20, Exelon Comments in Opposition to the Complaint, at 3 (Dec. 12, 2024) (“Constellation refers to Co-located Load as being ‘Fully Isolated’ and repeats that term again and again, but it remains untrue. If the loads at issue were truly ‘isolated,’ the PJM Tariff would not apply to them; no FERC-jurisdictional tariff would. And there would be no reason for this proceeding. As further discussed . . . the loads — whether they are what Constellation labels ‘fully isolated’ or not — unavoidably rely upon and use grid facilities and grid services in multiple ways. As a matter of physics and engineering, the load is fully integrated with the electric grid — this is the opposite of ‘Fully Isolated.’”).

⁷³ See, e.g., *Constellation Energy Generation v. PJM*, FERC Docket No. EL25-20, Comments of the Illinois Attorney General, at 12–13 (Dec. 12, 2024); *Large Loads Co-located at General Facilities*, FERC Docket No. AD24-11-000, Post Technical Comments of the Organization of PJM States, Inc., at 4 (Dec. 9, 2024) (stating that “[t]ransmission customers have paid the costs of supporting the grid necessary to allow [] nuclear facilities to operate”).

⁷⁴ *PJM Interconnection, LLC*, FERC Docket No. ER24-2172 [hereinafter Susquehanna Nuclear Interconnection Agreement], Protest of Exelon Corporation & American Electric Power Service Corporation, Declaration of John J. Reed & Danielle S. Powers, at 4 (Jun. 24, 2024).

⁷⁵ *Susquehanna Nuclear Interconnection Agreement*, Motion for Leave to Answer and Answer of Constellation Energy Generation and Vistra Corp., at 11 (Jul. 10, 2024).

⁷⁶ See PJM, [2025/2026 Base Residual Auction Report](#), at 11 (2024).

⁷⁷ See [2024 Quarterly State of the Market Report for PJM: January Through September](#), MONITORING ANALYTICS 3 (2024). See also Buckeye Power Comments, at 15 (Aug. 29, 2024) (“Co-location of data centers at existing multi-unit generators (nuclear plants are considered ideal) appears, at first blush, to be attractive as it can ‘free-up’ transmission capacity by reducing the net output of the generators that the transmission system must deliver. But co-location is a complicated scenario that can disrupt power markets and shift costs by removing large blocks of reliable base load power that will need to be replaced by other sources that will likely require transmission expansion elsewhere.”); *Constellation Energy Generation v. PJM*, FERC Docket No. EL25-20, Comments of the Illinois Attorney General, at 3–4 (Dec. 12, 2024) (“The OAG’s primary concern regarding co-location arrangements is the impact on resource adequacy and electricity energy and capacity prices The effect of removing the Illinois nuclear power plant capacity from the ComEd zone and from the PJM market generally can be expected to drive up prices In light of these multiple factors that are currently putting pressure on prices, co-location arrangements that reserve large blocks of power for discrete customers and prevent them from serving the grid as a whole can be expected to affect the 2027/2028 [capacity prices] . . .

. The OAG is concerned that co-location arrangements that abruptly remove large resources with high capacity values from the grid will cause further devastating price increases while the PJM markets struggle to respond.”).

⁷⁸ See *infra* Section III.C.

⁷⁹ See *Constellation Energy Generation v. PJM*, FERC Docket No. EL25-20, Constellation Complaint, at 6–7 (Nov. 22, 2024) (“competition to serve data center loads [is] a threat to [utilities] bottom line”).

⁸⁰ *Id.* (“Exelon’s utilities already have taken the position that this Commission has decreed that Fully Isolated Co-Located Load is ‘impossible’ – and shut down any attempt by customers to co-locate data center load in their utility systems. As detailed in their petition for declaratory order filed in Docket No. EL24-149, Exelon is refusing to process necessary studies on these grounds, demanding expensive upgrades under their unified interconnection procedures, delaying agreed-upon work which will force a nuclear plant to take additional outages, and forcing additional services to be procured.”).

⁸¹ See *PJM Interconnection, LLC*, 190 FERC ¶ 61,115 (Feb. 20, 2025) (instituting a show cause proceeding pursuant to section 206 of the FPA, and directing PJM and the Transmission Owners to either (1) show cause as to why the Tariff “remains just and reasonable and not unduly discriminatory or preferential without provisions addressing the sufficient clarity or consistency the rates, terms, and conditions of service that apply to co-location arrangements; or (2) explain what changes to the Tariff would remedy the identified concerns if the Commission were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory or preferential, and therefore, proceeds to establish a replacement Tariff”).

⁸² See *In the Matter of: Electronic Tariff Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC*, Kentucky Pub. Serv. Comm’n Case No. 2022-00387, at 2–4 (Aug. 28, 2023) (citing *Investigation into the Implementation of Economic Development Rates by Electric & Gas Utilities*, Kentucky Pub. Serv. Comm’n Admin. Case No. 327 (Sep. 24, 1990), *aff’d*, Kentucky Power Co. v. PSC of Kentucky, Franklin Circuit Court, Div. 1, Civil Action No. 23-CI-00899 (Dec. 30, 2024)).

⁸³ *Id.*

⁸⁴ See AEP Ohio Proposed Tariff Modifications, Ohio Power Company Testimony, at 2 (May 13, 2024). AEP Ohio requested PUC approval to create two new customer classifications: data centers with a monthly maximum demand of 25 MW or greater, and mobile data centers (cryptocurrency miners) with a monthly maximum demand of 1 MW or greater. AEP’s proposed tariff would include new obligations for these customer classes, including a minimum demand charge of 90 percent for data centers, and 95 percent for cryptocurrency facilities, as opposed to the standard 60 percent minimum demand charge for other customers in the general service rate class. AEP Ohio would also require: the two customer classes enter into energy service agreements (ESAs) for an initial term of at least ten years, as opposed to the typical term of one to five years; requirements to pay an exit fee equal to three years of minimum charges should the customer cancel the ESA after five years; collateral requirements tied to the customer’s credit ratings; requirements to reduce demand on AEP Ohio’s system during an emergency event; and requirements to participate in a separate energy procurement auction than standard offer service customers

⁸⁵ *Id.* at 7–8.

⁸⁶ AEP Ohio Proposed Tariff Modifications, Initial Comments of Data Center Coalition, at 9–12 (Jun. 25, 2024).

⁸⁷ *Basin Electric Power Cooperative*, 188 FERC ¶ 61,132 at PP 15–16, 61 (2024).

⁸⁸ *Id.* at P 95.

⁸⁹ See [H.B. 2101](#), 2025 Gen. Assemb., Reg. Sess. (Va. 2025).

⁹⁰ See Indiana Michigan Power Proposed Tariff Modifications, *supra* note 15, Direct Testimony of Andrew J. Williamson on Behalf of Indiana Michigan Power Company, at 5 (Jul. 19, 2024).

⁹¹ *Id.* at 3, 6–7.

⁹² *Id.* at 14.

⁹³ *Id.*; *id.* at 16 (tariff terms ensure data center provides “reasonable financial support for the significant transmission and generation infrastructure needed to serve large loads”).

⁹⁴ Indiana Michigan Power Proposed Tariff Modifications, *supra* note 15, Direct Testimony of Benjamin Inskeep on Behalf of Citizens Action Coalition of Indiana, Inc. [hereinafter Citizens Action Coalition of Indiana Testimony], at 25 (Oct. 15, 2024).

⁹⁵ *Id.* at 36.

⁹⁶ *Id.* at 24–31.

⁹⁷ Indiana Michigan Power Proposed Tariff Modifications, *supra* note 15, Direct Testimony of Carolyn A. Berry on Behalf of Amazon Web Services, at 16 (Oct. 15, 2024).

⁹⁸ *Id.*

⁹⁹ *Id.*

¹⁰⁰ See generally *Application of Nevada Power Company to Implement Clean Transition Tariff Schedule*, Nevada Pub. Util. Comm'n Docket No. 24-05023 [Nevada Power Clean Transition Tariff], Direct Testimony of Manuel N. Lopez on Behalf of Regulatory Operations Staff (Jan. 16, 2025); Nevada Power Clean Transition Tariff, Direct Testimony of Jeremy I. Fisher on Behalf of Sierra Club, Docket No. PUCN 24-05023, at 10–20 (Jan. 16, 2025).

¹⁰¹ See generally Nevada Power Clean Transition Tariff, Direct Testimony of Manuel N. Lopez on Behalf of Regulatory Operations Staff, at 7–8 (Jan. 16, 2025).

¹⁰² Nevada Power Clean Transition Tariff, Stipulation (Feb. 7, 2025).

¹⁰³ See, e.g., GA. CODE ANN. § 46-3-8 (allowing utilities to compete to provide service to certain new customers demanding at least 900 kilowatts).

¹⁰⁴ See Indiana Michigan Power Proposed Tariff Modifications, *supra* note 15, Citizens Action Coalition of Indiana Testimony, at 11 (Oct. 15, 2024) (“Using I&M witness Williamson’s example portfolio that has an average resource cost of \$2,000/kW and has an average accredited capacity of 50%, I&M will also need to make \$17.6 billion in new generation investments to serve 4.4 GW of new hyperscaler load.”).

¹⁰⁵ ERIC GIMON, MARK AHLSTROM & MIKE O’BOYLE, ENERGY PARKS: A NEW STRATEGY TO MEET RISING ELECTRICITY DEMAND 7 (Energy Innovation Policy & Technology, Dec. 2024).

¹⁰⁶ *Id.* at 8.

¹⁰⁷ See *id.* at 19.

¹⁰⁸ See *id.* at 8–21.

¹⁰⁹ See, e.g., *State ex rel. Utilities Commission v. North Carolina Waste Awareness and Reduction Network*, 805 S.E.2d 712 (N.C. Ct. App. 2017), *aff’d per curiam*, 371 N.C. 109, 617 (2018).

¹¹⁰ See *Sawnee Electric Membership Corporation v. Public Service Comm’n*, 371 Ga. App. 267, 270 (2024) (“ . . . [T]he text of the Act assigns each geographic area to an electric supplier but also includes the large load exception to allow customers to choose their electric supplier if certain conditions exist . . . the premises must be ‘utilized by one consumer and have single-metered service’”).

¹¹¹ See generally David Roberts, [Assembling Diverse Resources Into Super-Powered “Energy Parks:” A Conversation with Eric Gimon of Energy Innovation](#), VOLTS (Jan. 15, 2025) (featuring an Energy Innovation author describing energy parks in rural cooperative territory in Texas).

¹¹² See, e.g., *Paoli Mun. Light Dept. v. Orange County Rural Elec. Membership Corp.*, 904 N.E.2d 1280 (Ind. Ct. App. 2009) (ruling in favor of a cooperative utility that sued to prevent a municipal utility from providing electric service to a facility owned by that municipality but located within the cooperative’s service territory).

¹¹³ See, e.g., [Power for Tomorrow](#) (last visited Jan. 29, 2025), which claims to be “the nation’s leading resource” about the “regulated electric utility model” and generally opposes competition with utilities, in part by claiming that competition harms residential consumers. The effort is funded by utilities. See Energy and Policy Institute, [Power for Tomorrow](#) (last visited Jan. 29, 2025).

¹¹⁴ AEP Ohio Proposed Tariff Modifications, Testimony of Paul Sotkiewicz on Behalf of the Retail Energy Supply Association, at 9–10 (Aug. 29, 2024).

¹¹⁵ *Id.* at 15.

¹¹⁶ *Id.* at 14–15.

¹¹⁷ The trade group’s analyst observed that in January 2023 AEP projected only 248 megawatts of data center growth through 2038, but one year later AEP projected 3,700 megawatts of data center growth by 2030. *Id.* at 10 (citing PJM reports).

¹¹⁸ TYLER NORRIS ET AL., [RETHINKING LOAD GROWTH: ASSESSING THE POTENTIAL FOR INTEGRATION OF LARGE FLEXIBLE LOADS IN U.S. POWER SYSTEMS](#) 18 (Nicholas Institute for Energy, Environment & Sustainability, 2025).

¹¹⁹ *Id.* at 5–6.

¹²⁰ See Ari Peskoe, *Replacing the Utility Transmission Syndicate’s Control*, 44 ENERGY L. J. 547 (2023).

¹²¹ Exec. Order No. 14,141, 90 FR 5469 (2025).

¹²² *Id.*

¹²³ Va. J. Legis. Audit & Rev. Commission 2024-548, [Report to the Governor & the General Assembly of Virginia: Data Centers in Virginia](#), at viii (2024).

¹²⁴ Brody Ford & Matt Day, [Price Tag Jumps for Amazon’s Mississippi Data Centers Jump 60% to \\$16 Billion](#), BLOOMBERG (Jan. 31, 2025).

¹²⁵ *Id.*

¹²⁶ See generally NATHAN SHREVE, ZACHARY ZIMMERMAN & ROB GRAMLICH, [FEWER NEW MILES: THE US TRANSMISSION GRID IN THE 2020s](#), GRID STRATEGIES (Jul. 2024).

¹²⁷ U.S. Department of Energy, [National Transmission Needs Study](#) (Oct. 30, 2023).

¹²⁸ See Ari Peskoe, *Replacing the Utility Transmission Syndicate’s Control*, 44 ENERGY L. J. 547 (2023)

¹²⁹ Sonali Razdan, Jennifer Downing & Louise White, [Pathways to Commercial Liftoff: Virtual Power Plants 2025 Update](#), U.S. Department of Energy Loan Programs Office (Jan. 2025).

¹³⁰ See, e.g., Mississippi Power Company's Notice of IRP Cycle, Mississippi Public Service Comm'n Docket No. 2019-UA-231 (Jan. 9, 2025) (stating that because the utility has entered into two contracts with 600 MW of new load it will keep at least one coal plant open that had been slated for retirement); Mississippi Power Special Contract Filing, Mississippi Public Service Comm'n Docket No. 2025-UN-3 (Jan. 9, 2025) (showing that at least one of the two special contracts is with a data center).



Generator Interconnection Queue Update

System Planning Committee
of the Board of Directors

December 10, 2024

Executive Summary



- Forward resource adequacy assessments indicate a growing supply-demand gap magnified by economic development drivers and new large spot load additions; supply-side frictions contribute to delays of new resources
- Though MISO remains committed to Queue enhancements like the recently filed Queue Volume Cap and the automation of early-stage studies, those efforts are insufficient to meet near-term regional needs
- MISO is developing an Expedited Resource Adequacy Study (ERAS) process to expedite interconnections until enhancements reduce the Queue study process timeline

Many factors continue to drive changing and increasing resource adequacy risk



Continued large volumes of Generator Interconnection Queue requests and accumulating backlog prevent one-year study timeframe



Delays getting projects with signed interconnection agreements built due to supply chain bottlenecks, permitting delays and commercial challenges

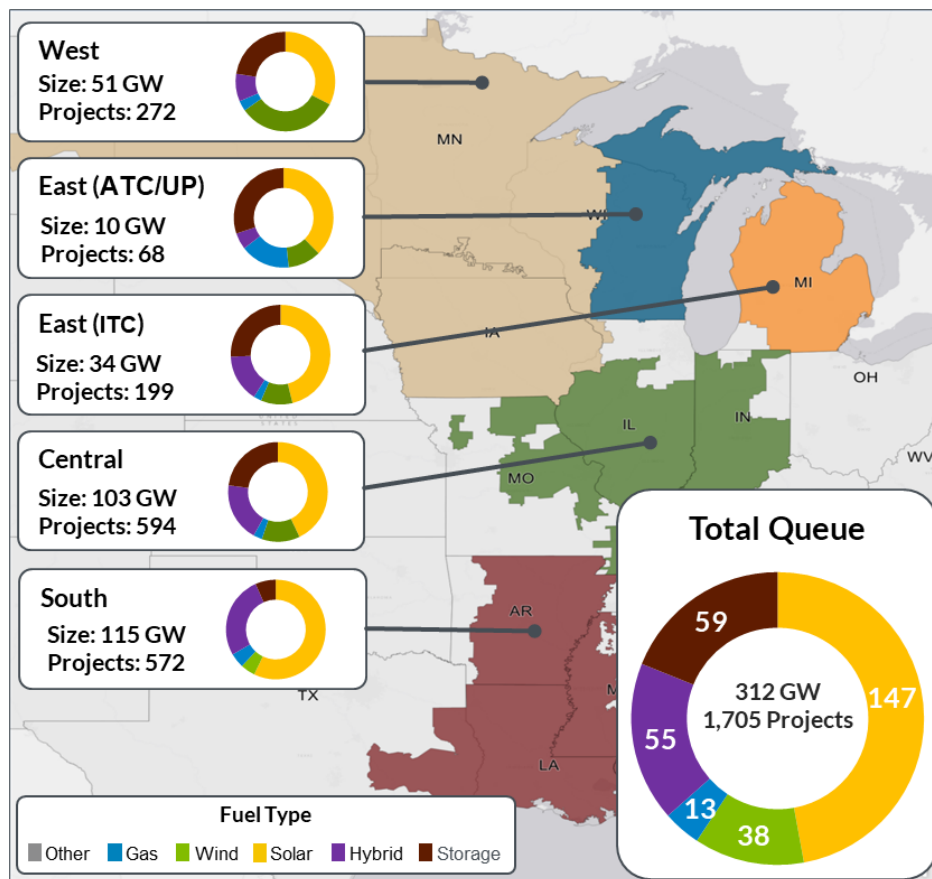


Load growth due to economic development and new, large spot load additions and lack of ability to concurrently add new resources



Continuing rapid pace of resource retirements

MISO's large Queue volume and a backlog of applications are contributing to the delay of resource additions



CURRENT QUEUE

- Tariff time is 1-year
- Cycles are taking 3-4 years
 - Late-stage dropouts from 2020-2022 require restudies and prevent processing of later cycles
- Generator Interconnection Agreements are required now for projects aimed at meeting resource adequacy needs in the next 3-5 years

Queue data as of 11/4/2024

MISO has been actively improving the manageability of its Queue to provide a critical path to timely resource approvals, but it may take several years to reduce Queue processing to a one-year timeframe

2024 Accomplishments	2025 Plans	
	Queue Improvements	Support for Timely Resource Additions
• Implemented FERC-approved reforms • Filed compliance with FERC Order 2023 • Received FERC approval of JTIQ framework	• Implement Queue Cap upon receiving FERC approval • Begin using innovative software for automation of early Queue phases	• Commercial Operation Date tracker tool and web postings • Launch Expedited Resource Adequacy Study (ERAS) process



Improvements are addressing the Queue backlog, improving certainty of projects and addressing resource adequacy needs

New software and the Queue Volume Cap will help achieve a more manageable number of requests and a one-year processing timeline

QUEUE VOLUME CAP

- Cap is 50% of each planning region's non-coincident peak load

Filed Nov.
2024 with
requested
effective date
of Jan. 2025

Projects over Cap will be first in line for the next cycle, per submission timestamp

- Addresses engineering problem of only serving load with new requests
 - More realistic resource dispatch, models and analysis
- FERC guidance incorporated in MISO's refiling

AUTOMATION

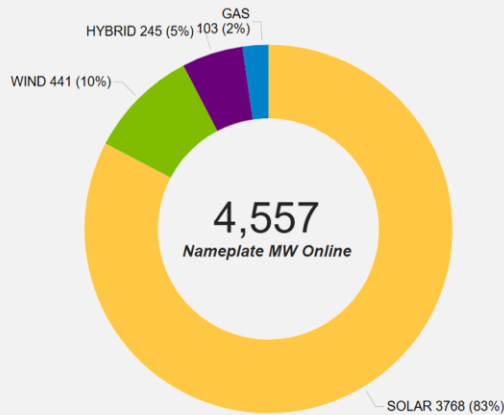
- Enables early-stage studies to run in parallel in the cloud
- Increases the efficiency of power flow model build processes
- Provides customers information more quickly
 - Pre-screen
 - Power flow models
 - Network Upgrade identification and cost allocation
 - System Impact Study (SIS) reports
- Additional automation is planned

Increased data transparency and ongoing updates help inform the resource planning landscape in the MISO region

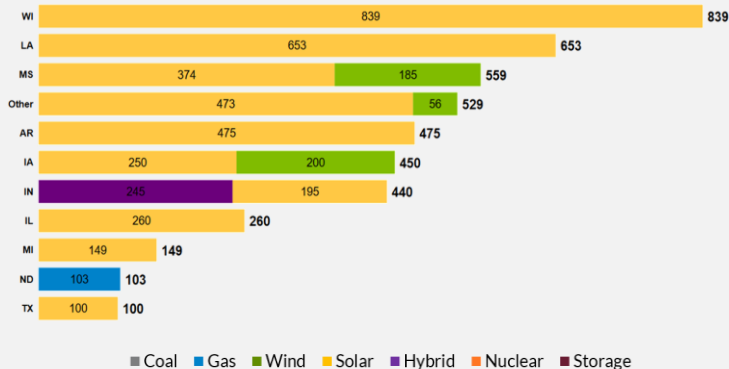
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CEO Witness Siddique
Date: June 12, 2025
Page 7 of 9

Commercial Operation Date (COD) information that will be shared online

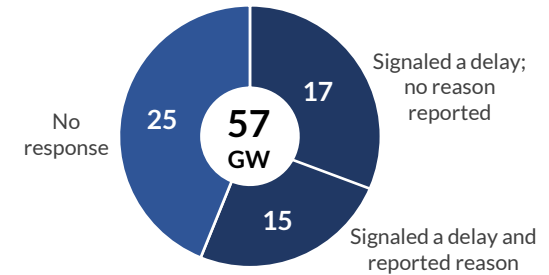
GENERATION ADDED IN 2024* NAMEPLATE (MW)



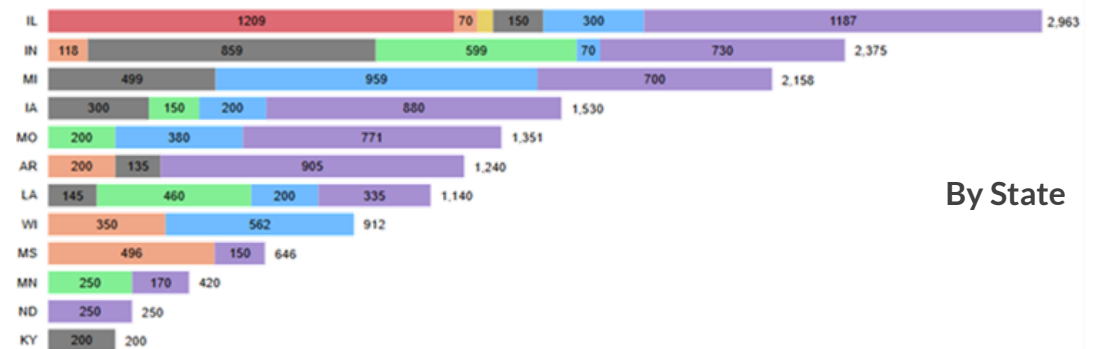
By State



SURVEY OF DELAYED PROJECTS**

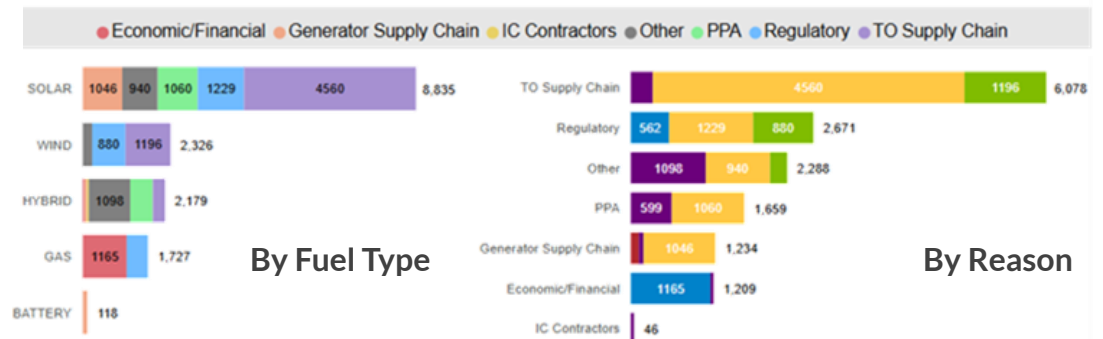


DELAY REASONS (MW)



By State

By Fuel Type

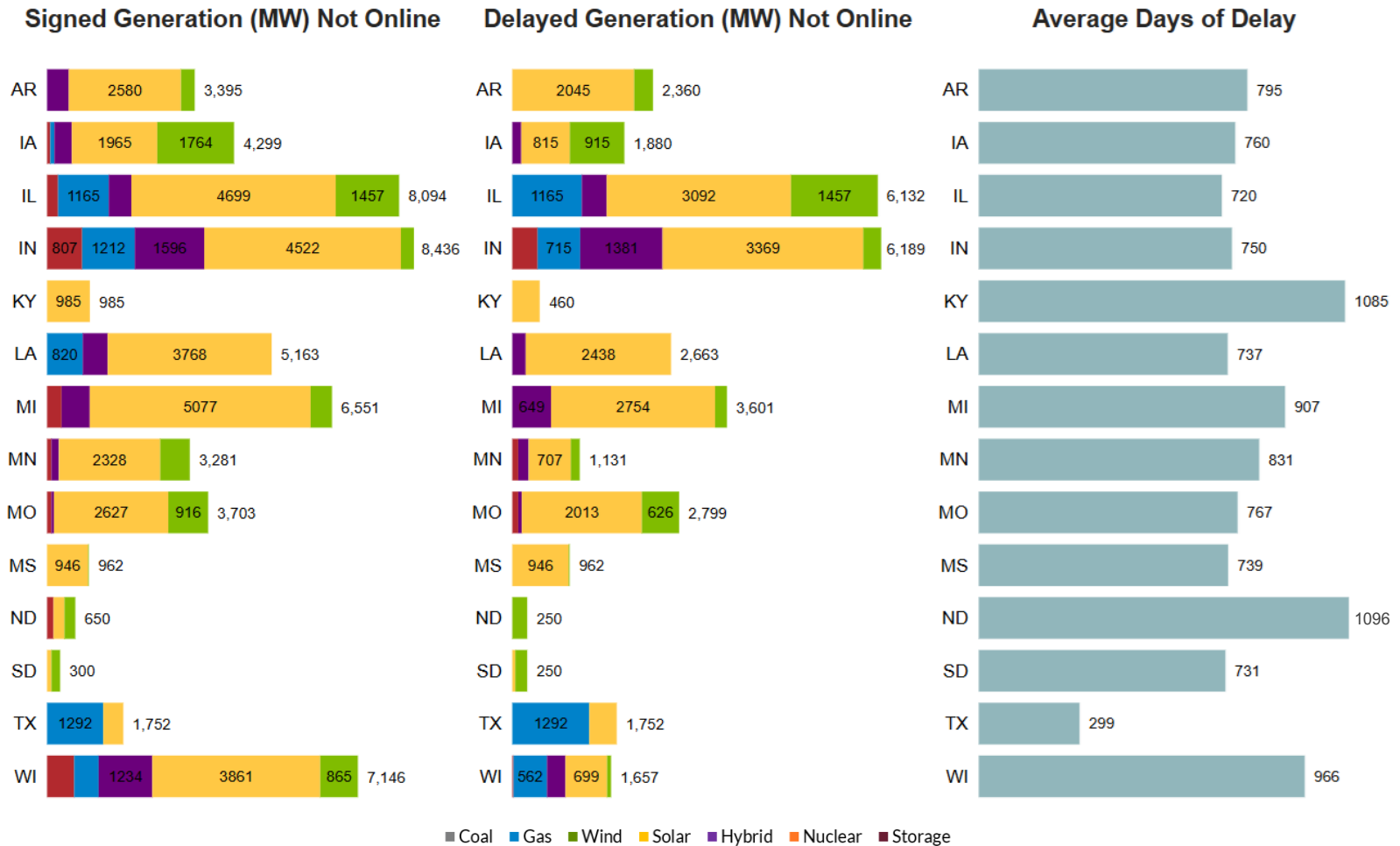


By Reason

*Data as of 11/23/2024. **Additional capacity that can add to the 2024 totals is in the testing phase.

Additional data views on state-level details show location and extent of delays

Examples of shared data and information*



*Data as of 11/23/2024

MISO is proposing the Expedited Resource Adequacy Study (ERAS) process as a short-term solution to address capacity concerns until the Queue backlog and study timeline are reduced

Projects must
be recognized
by their
regulatory
authority



Addresses Load Serving Entities with resource adequacy needs that must be resolved within the next five years



Projects would be evaluated individually instead of in clusters, allowing GIA execution within months versus years



ERAS would be available for new projects and some existing projects in the Queue



Rethinking Load Growth

Assessing the Potential for Integration of Large Flexible Loads in US Power Systems

Tyler H. Norris, Tim Profeta, Dalia Patino-Echeverri, and Adam Cowie-Haskell

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<https://nicholasinstitute.duke.edu/publications/rethinking-load-growth>

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Nicholas Institute for Energy, Environment & Sustainability



The Nicholas Institute for Energy, Environment & Sustainability at Duke University accelerates solutions to critical energy and environmental challenges, advancing a more just, resilient, and sustainable world. The Nicholas Institute conducts and supports actionable research and undertakes sustained engagement with policymakers, businesses, and communities—in addition to delivering transformative educational experiences to empower future leaders. The Nicholas Institute's work is aligned with the [Duke Climate Commitment](#), which unites the university's education, research, operations, and external engagement missions to address climate challenges.

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INTRODUCTION

A New Era of Electricity Demand

Rapid US load growth—driven by unprecedented electricity demand from data centers, industrial manufacturing, and electrification of transportation and heating—is colliding with barriers to timely resource expansion. Protracted interconnection queues, supply chain constraints, and extended permitting processes, among other obstacles, are limiting the development of new power generation and transmission infrastructure. Against this backdrop, there is increasing urgency to identify strategies that accommodate rising demand without compromising reliability, affordability, or progress on decarbonization.

Aggregated US winter peak load is forecasted to grow by 21.5% over the next decade, rising from approximately 694 GW in 2024 to 843 GW by 2034, according to the *2024 Long-Term Reliability Assessment* of the North American Electric Reliability Corporation. This represents a 10-year compound annual growth rate (CAGR) of 2.0%, higher than any period since the 1980s (NERC 2024). Meanwhile, the Federal Energy Regulatory Commission's (FERC) latest five-year outlook forecasts 128 GW in peak load growth as early as 2029—a CAGR of 3.0% (FERC 2024b).

The primary catalyst for these updated forecasts is the surge in electricity demand from large commercial customers. While significant uncertainty remains, particularly following the release of DeepSeek, data centers are expected to account for the single largest growth segment, adding as much as 65 GW through 2029 and up to 44% of US electricity load growth through 2028 (Wilson et al. 2024; Rouch et al. 2024). Artificial intelligence (AI) workloads are projected to represent 50% to 70% of data center demand by 2030—up from less than 3% at the start of this decade—with generative AI driving 40% to 60% of this growth (Srivathsan et al. 2024; Lee et al. 2025).

Analysts have drawn parallels to the 1950s through the 1970s, when the United States achieved comparable electric power sector growth rates (Wilson et al. 2024). Yet these comparisons arguably understate the nature of today's challenge in the face of stricter permitting obstacles, higher population density, less land availability, skilled labor shortages, persistent supply chain bottlenecks, and demand for decarbonization and greater power reliability. While historical growth rates offer a useful benchmark, the sheer volume of required new generation, transmission, and distribution capacity forecasted for the United States within a condensed timeframe appears unprecedented.

The immensity of the challenge underscores the importance of deploying every available tool, especially those that can more swiftly, affordably, and sustainably integrate large loads. The time-sensitivity for solutions is amplified by the market pressure for many of these loads to interconnect as quickly as possible. In recent months, the US Secretary of Energy Advisory Board (SEAB) and the Electrical Power Research Institute (EPRI) have highlighted a key solution: load flexibility (SEAB 2024, Walton 2024a). The promise is that the unique profile of AI data centers can facilitate more flexible operations, supported by ongoing advancements in distributed energy resources (DERs).

Flexibility, in this context, refers to the ability of end-use customers to temporarily reduce their electricity consumption from the grid during periods of system stress by using on-site generators, shifting workload to other facilities, or reducing operations.¹ When system planners can reliably anticipate the availability of this load flexibility, the immediate pressure to expand generation capacity and transmission infrastructure can potentially be alleviated, mitigating or deferring costly expenditures. By facilitating near-term load growth without prematurely committing to large-scale capacity expansion, this approach offers a hedge against mounting uncertainty in the US data center market in light of the release of DeepSeek and related developments (Kearney and Hampton 2025).

Summary of Analysis and Findings

To support evaluation of potential solutions, this study presents an analysis of the existing US electrical power system's ability to accommodate new flexible loads. The analysis, which encompasses 22 of the largest balancing authorities serving 95% of the country's peak load, provides a first-order estimate of the potential for accommodating such loads with minimal capacity expansion or impact on demand-supply balance.²

Specifically, we estimate the gigawatts of new load that could be added in each balancing authority (BA) before total load exceeds what system planners are prepared to serve, provided the new load can be temporarily curtailed as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.

Key results include (see [Figure 1](#)):

- 76 GW of new load—equivalent to 10% of the nation's current aggregate peak demand—could be integrated with an average annual load curtailment rate of 0.25% (i.e., if new loads can be curtailed for 0.25% of their maximum uptime)
- 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5%, and 126 GW at a rate of 1.0%
- The number of hours during which curtailment of new loads would be necessary per year, on average, is comparable to those of existing US demand response programs
- The average duration of load curtailment (i.e., the length of time the new load is curtailed during curtailment events) would be relatively short, at 1.7 hours when average annual load curtailment is limited to 0.25%, 2.1 hours at a 0.5% limit, and 2.5 hours at a 1.0% limit
- Nearly 90% of hours during which load curtailment is required retain at least half of the new load (i.e., less than 50% curtailment of the new load is required)
- The five balancing authorities with the largest potential load integration at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW³

1 Note that while *curtailment* and *flexibility* are used interchangeably in this paper, *flexibility* can refer to a broader range of capabilities and services, such as the provision of down-reserves and other ancillary services.

2 For further discussion on the nuances regarding generation versus transmission capacity, see the [section on limitations](#).

3 A [complete list of abbreviations](#) and their definitions can be found at the end of the report.

Overall, these results suggest the US power system's existing headroom, resulting from intentional planning decisions to maintain sizable reserves during infrequent peak demand events, is sufficient to accommodate significant constant new loads, provided such loads can be safely scaled back during some hours of the year. In addition, they underscore the potential for leveraging flexible load as a complement to supply-side investments, enabling growth while mitigating the need for large expenditures on new capacity.

We further demonstrate that a system's potential to serve new electricity demand without capacity expansion is determined primarily by the system's load factor (i.e., a measure of the level of use of system capacity) and grows in proportion to the flexibility of such load (i.e., what percentage of its maximal potential annual consumption can be curtailed). For this reason, in this paper we assess the technical potential for a system to serve new load under different curtailment limit scenarios (i.e., varying curtailment tolerance levels for new loads).

The analysis does not consider the technical constraints of power plants that impose intertemporal constraints on their operations (e.g., minimum downtime, minimum uptime, startup time, ramping capability, etc.) and does not account for transmission constraints. However, it ensures that the estimate of load accommodation capacity is such that total demand does not exceed the peak demand already anticipated for each season by system planners, and it discounts existing installed reserve margins capable of accommodating load that exceeds historical peaks. It also assumes that new load is constant throughout all hours.

This analysis should not be interpreted to suggest the United States can fully meet its near- and medium-term electricity demands without building new peaking capacity or expanding the grid. Rather, it highlights that flexible load strategies can help tap existing headroom to more quickly integrate new loads, reduce the cost of capacity expansion, and enable greater focus on the highest-value investments in the electric power system.

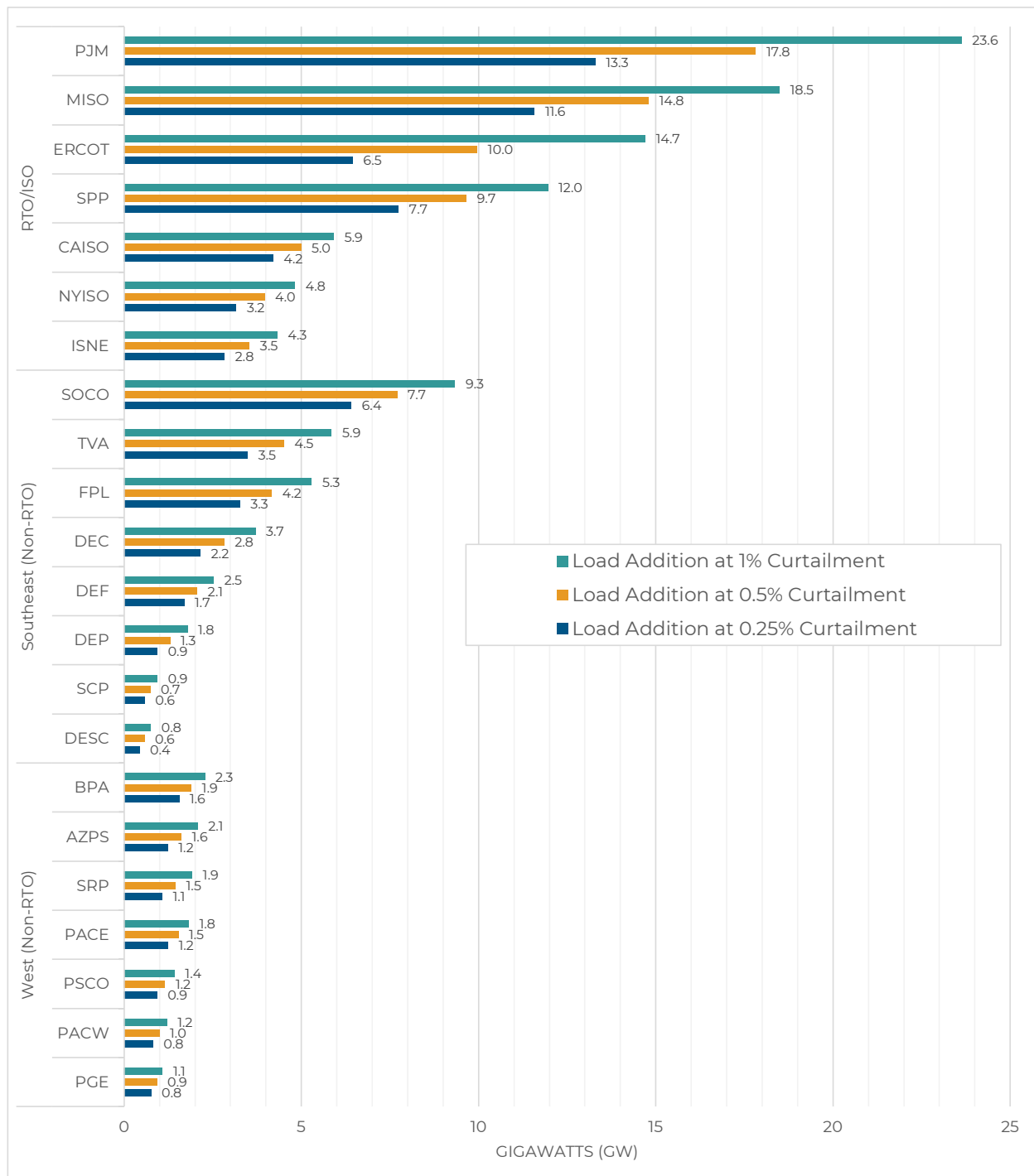
This paper proceeds as follows: [the following section provides background](#) on the opportunities and challenges to integrating large new data centers onto the grid. It explores how load flexibility can accelerate interconnection, reduce ratepayer costs through higher system utilization, and expand the role of demand response, particularly for AI-specialized data centers. We then detail the [methods and results for estimating curtailment-enabled headroom](#), highlighting key trends and variations in system headroom and its correlation with load factors across regions. The paper concludes with a [brief overview of key findings, limitations, and near-term implications](#).

BACKGROUND

Load Flexibility Can Accelerate Grid Interconnection

The growing demand for grid access by new large loads has significantly increased interconnection wait times, with some utilities reporting delays up to 7 to 10 years ([Li et al. 2024](#); [Saul 2024](#); [WECC 2024](#)). These wait times are exacerbated by increasingly severe transmission equipment supply chain constraints. In June 2024, the President's National Infrastructure Advisory Council highlighted that transformer order lead times had ballooned to two to five years—up from less than one year in 2020—while costs surged by 80% ([NIAC 2024](#)). Circuit breakers have seen similar delays: last year, the Western Area Power Administration

Figure 1. System Headroom Enabled by Load Curtailment of New Load by Balancing Authority, GW



Note: *System headroom* refers to the amount of GW by which a BA's load can be augmented every hour in the absence of capacity expansion so that, provided a certain volume of curtailment of the new load, the total demand does not exceed the supply provisioned by system planners to withstand the expected highest peak. The headroom calculation assumes the new load is constant and hence increases the total load by the same GW hour-by-hour.

reported lead times of up to four and a half years for lower voltage classes and five and a half years for higher voltage classes, alongside a 140% price hike over two years (Rohrer 2024). Wood Mackenzie reported in May 2024 that lead times for high-voltage circuit breakers reached 151 weeks in late 2023, marking a 130% year-over-year increase (Boucher 2024).

Large load interconnection delays have recently led to growing interest among data centers in colocating with existing generation facilities. At a FERC technical conference on the subject in late 2024 (FERC 2024c), several participants highlighted the potential benefits of colocation for expedited interconnection,⁴ a view echoed in recent grey literature (Schatzki et al. 2024). Colocation, however, represents only a portion of load interconnections and is not viewed as a long-term, system-wide solution.

Load flexibility similarly offers a practical solution to accelerating the interconnection of large demand loads (SIP 2024, Jabeck 2023). The most time-intensive and costly infrastructure upgrades required for new interconnections are often associated with expanding the transmission system to deliver electricity during the most stressed grid conditions (Gorman et al. 2024). If a new load is assumed to require firm interconnection service and operate at 100% of its maximum electricity draw at all times, including during system-wide peaks, it is far more likely to trigger the need for significant upgrades, such as new transformers, transmission line reconductoring, circuit breakers, or other substation equipment.

To the extent a new load can temporarily reduce (i.e., curtail) its electricity consumption from the grid during these peak stress periods, however, it may be able to connect while deferring—or even avoiding—the need for certain upgrades (ERCOT 2023b). A recent study on Virginia’s data center electricity load growth noted, “Flexibility in load is generally expected to offset the need for capacity additions in a system, which could help mitigate the pressure of rapid resource and transmission expansion” (K. Patel et al. 2024). The extent and frequency of required curtailment would depend on the specific nature of the upgrades; in some cases, curtailment may only be necessary if a contingency event occurs, such as an unplanned transmission line or generator outage. For loads that pay for firm interconnection service, any period requiring occasional curtailment would be temporary, ending once necessary network upgrades are completed.⁵ Such “partially firm,” flexible service was also highlighted by participants in FERC’s 2024 technical conference on colocation.⁶

Traditionally, such arrangements have been known as *interruptible* electric service. More recently, some utilities have pursued *flexible* load interconnection options. In March 2022, for example, ERCOT implemented an interim interconnection process for large loads seeking to connect in two years or less, proposing to allow loads seeking to qualify as controllable load resources (CLRs) “to be studied as flexible and potentially interconnect more MWs” (ERCOT 2023b). More recently, ERCOT stated that “the optimal solution for grid reliability is for

4 For example, the Clean Energy Buyers Association (2024) noted, “Flexibility of co-located demand is a key asset that can enable rapid, reliable interconnection.”

5 Such an arrangement is analogous to provisional interconnection service available to large generators, as defined in Section 5.9.2 of FERC’s *Pro Forma Large Generator Interconnection Agreement* (LGIA).

6 MISO’s market monitor representative stated, “instead of being a network firm customer, could [large flexible loads] be a non-firm, or partial non-firm [customer], and that could come with certain configuration requirements that make them truly non-firm, or partially non-firm. But, all those things are the things that could enable some loads to get on the system quicker” (FERC 2024c).

more loads to participate in economic dispatch as CLRs” (Springer 2024). Similarly, Pacific Gas and Electric (PG&E) recently introduced a Flex Connect program to allow certain loads faster access to the grid (Allsup 2024).

These options resemble interconnection services available to large generators that forgo capacity compensation, and potentially higher curtailment risk, in exchange for expedited lower-cost grid access (Norris 2023). FERC codified this approach with Energy Resource Interconnection Service (ERIS) in Order 2003 and revisited the concept during a 2024 technical workshop to explore potential improvements (Norris 2024). Some market participants have since proposed modifying ERIS to facilitate the colocation of new generators with large loads (Intersect Power 2024).

Ratepayers Benefit from Higher System Utilization

The US electric power system is characterized by a relatively low utilization rate, often referred to as the *load factor*. The load factor is the ratio of average demand to peak demand over a given period and provides a measure of the utilization of system capacity (Cerna et al. 2023). A system with a high load factor operates closer to its peak system load for more hours throughout the year, while a system with a low load factor generally experiences demand spikes that are higher than its typical demand levels (Cerna et al. 2022). This discrepancy means that, for much of the year, a significant portion of a system’s available generation and transmission infrastructure is underutilized (Cochran et al. 2015).

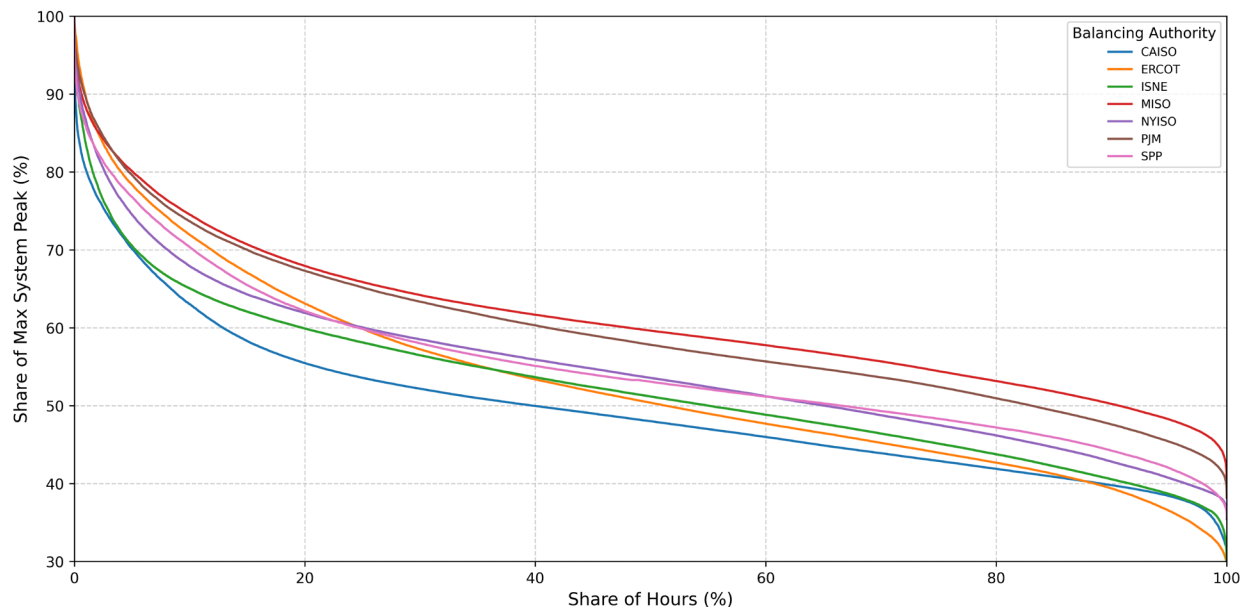
The power system is designed to handle the highest demand peaks, which in some cases may occur less than once per year, on average, due to extreme weather events. As a result, the bulk of the year sees demand levels well below that peak, leaving substantial headroom in installed capacity. Seasonal shifts add another layer of complexity: some balancing authorities may show higher load factors in summer, yet experience significantly lower utilization in winter, and vice versa.

The *load duration curve* (LDC) illustrates system utilization by ranking demand from highest to lowest over a given period. It provides a visual representation of how often certain demand levels occur, highlighting the frequency and magnitude of peak demand relative to average load. A steep LDC suggests high demand variability, with peaks significantly exceeding typical loads, while a flatter LDC indicates more consistent usage. Figure 2 presents LDCs for each US RTO/ISO based on hourly load between 2016 and 2024, standardized as a percentage of each system’s maximum peak demand to allow cross-market comparisons.

A system utilization rate below 100% is expected for most large-scale infrastructure designed to withstand occasional surges in demand. Nevertheless, when the gap between average demand and peak demand is consistently large, it implies that substantial portions of the electric power system—generation assets, transmission infrastructure, and distribution networks—remain idle for much of the year (Riu et al. 2024). These assets are expensive to build and maintain, and ratepayers ultimately bear the cost.

Once the infrastructure is in place, however, there is a strong economic incentive to increase usage and spread these fixed costs over more kilowatt-hours of delivered electricity. An important consideration is therefore the potential for additional load to be added without significant new investment, provided the additional load does not raise the system’s overall

Figure 2. Load Duration Curve for US RTO/ISOs, 2016–2024



This figure is adapted from the [analysis section of this paper](#), which contains additional detail on the data and method.

peak demand and thereby trigger system expansion.⁷ When new loads are flexible enough to avoid a high coincident load factor, thereby mitigating contribution to the highest-demand hours, they fit within the existing grid’s headroom.⁸ By strategically timing or curtailing demand, these flexible loads can minimize their impact on peak periods. In doing so, they help existing customers by improving the overall utilization rate—thereby lowering the per-unit cost of electricity—and reduce the likelihood that expensive new peaking plants or network expansions may be needed.

In contrast, inflexible new loads that increase the system’s absolute peak demand can drive substantial additional needs for generation and transmission capacity. Even a modest rise in peak demand may trigger capital investments in peaking plants, fuel supply infrastructure, and reliability enhancements. These cost implications have contributed to increasingly contentious disputes in which regulators or ratepayer advocates seek to create mechanisms to pass the costs of serving large loads directly to those loads and otherwise ensure data centers do not shift costs via longer contract commitments, billing minimums, and upfront investment ([Howland 2024a](#); [Riu et al. 2024](#)). Some examples include:

- The **Georgia Public Service Commission (GPSC)**, citing “staggering” large load growth and the need to protect ratepayers from the costs of serving those customers, recently implemented changes to customer contract provisions if peak draw exceeds 100 MW, mandating a GPSC review and allowing the utility to seek longer contracts and minimum billing for cost recovery ([GPSC 2025](#)). This follows GPSC’s approval

⁷ See the [discussion on limitations and further analysis](#) in the following section for additional nuance.

⁸ Demand charges are often based on coincident consumption (e.g., ERCOT’s Four Coincident Peak charge uses the load’s coincident consumption at the system’s expected seasonal peak to determine an averaged demand charge that may account for >30% of a user’s annual bill).

of 1.4 GW of gas capacity proposed by Georgia Power in response to load growth “approximately 17 times greater than previously forecasted” through 2030/2031, a forecast it revised upward in late 2024 (GPC 2023, 2024).

- **Ohio**, where American Electric Power issued a moratorium on data center service requests, followed by a settlement agreement with the Public Service Commission staff and consumer advocates that calls for longer contract terms, load ramping schedules, a minimum demand charge, and collateral for service from data centers exceeding 25 MW (Ohio Power Company 2024).
- **Indiana**, where 4.4 GW of interconnection requests from a “handful” of data centers represents a 157% increase in peak load for Indiana Michigan Power over the next six years. Stakeholders there have proposed “firewalling” the associated cost of service from the rest of the rate base, wherein the utility would procure a separate energy, capacity, and ancillary resource portfolio for large loads and recover that portfolio’s costs from only the qualifying large loads (Inskip 2024).
- **Illinois**, where Commonwealth Edison reported that large loads have paid 8.2% of their interconnection costs while the remaining 91.8% is socialized across general customers (ComEd 2024).

These examples underscore the significance of exploring how flexible loads can mitigate peak increases, optimize the utilization of existing infrastructure, and reduce the urgency for costly and time-consuming capacity expansions.

Demand Response and Data Centers

Demand response refers to changes in electricity usage by end-use customers to provide grid services in response to economic signals, reliability events, or other conditions. Originally developed to reduce peak loads (also called *peak shaving*), demand response programs have evolved to encompass a variety of grid services, including balancing services, ancillary services, targeted deferral of grid upgrades, and even variable renewable integration (Hurley et al. 2013; Ruggles et al. 2021). Demand response is often referred to as a form of *demand-side management* or *demand flexibility* (Nethercutt 2023).

Demand response is the largest and most established form of virtual power plant (Downing et al. 2023), with 33 GW of registered capacity in wholesale RTO/ISO programs and 31 GW in retail programs as of 2023 (FERC 2024a).⁹ As a share of peak demand, participation in RTO/ISO programs ranges from a high of 10.1% in MISO to a low of 1.4% in SPP. A majority of enrolled capacity in demand response programs are industrial or commercial customers, representing nearly 70% of registered capacity in retail (EIA 2024).

Following a decade of expansion, growth in demand response program participation stalled in the mid-2010s partially because of depressed capacity prices, forecasted over-capacity, and increasingly restrictive wholesale market participation rules (Hledik et al. 2019). However, the resurgence of load growth and increasing capacity prices, coupled with ongoing advancements in DERs and grid information and communication technologies (ICT) appears likely to reverse this trend.

9 RTO/ISO and retail data may overlap.

Studies of national demand response potential have identified a range of potential scenarios (Becker et al. 2024), ranging as high as 200 GW by 2030 in a 2019 study, comprising 20% of the then-forecasted system peak and yielding \$15 billion in annual benefits primarily via avoided generation and transmission and distribution (T&D) capacity (Hledik et al. 2019). Notably, this research was conducted before recent load growth forecasts.

The Participation Gap: Data Centers and Demand Response

For nearly two decades, computational loads—and data centers in particular—have been identified as a promising area for demand response. Early studies explored these capabilities, such as a two-phase Lawrence Berkeley National Laboratory study drawing on six years of research, which concluded in 2010 that “data centers, on the basis of their operational characteristics and energy use, have significant potential for demand response” (Ghatikar et al. 2010) and in 2012 that “[certain] data centers can participate in demand response programs with no impact to operations or service-level agreements” (Ghatikar et al. 2012). The 2012 study provided one of the earliest demonstrations of computational load responsiveness, finding that 10% load shed can typically occur within 6 to 15 minutes.

Despite this promise, data centers have historically exhibited low participation rates in demand response programs as a result of operational priorities and economic incentives (Basmadjian 2019; Clausen et al. 2019; Wierman et al. 2014). Data centers are designed to provide reliable, uninterrupted service and generally operate under service-level agreements (SLAs) that mandate specific performance benchmarks, including uptime, latency, and overall quality of service. Deviation from these standards can result in financial penalties and reputational harm, creating a high-stakes environment where operators are averse to operational changes that introduce uncertainty or risk (Basmadjian et al. 2018).

Compounding this challenge is the increasing prevalence of large-scale colocated data centers, which represent a significant share of the data center market (Shehabi et al. 2024). These facilities house multiple tenants, each with varying operational requirements. Coordinating demand response participation in such environments introduces layers of administrative and logistical complexity, as operators must mediate cost- and reward-sharing agreements among tenants. Further, while data centers possess significant technical capabilities, tapping these capabilities for demand response requires sophisticated planning and expertise, which some operators may not have needed to date (Silva et al. 2024).

Economic considerations have further compounded this reluctance. Implementing a demand response program requires investments in advanced energy management systems, staff training, and integration with utility platforms for which costs can be material, particularly for smaller or midsized facilities. At the same time, financial incentives provided by most demand response programs have historically been modest and insufficient to offset the expenses and opportunity costs associated with curtailed operations. For operators focused on maintaining high utilization rates and controlling costs, the economic proposition of demand response participation may be unattractive.

Existing demand response program designs may inadvertently discourage participation. Many programs were originally created with traditional industrial consumers in mind, with different incentives and operational specifications. Price-based programs may require high price variability to elicit meaningful responses, while direct control programs without sufficient guardrails may introduce unacceptable risks related to uptime and performance. The

complexity of active participation in demand response markets, including bidding processes and navigating market mechanisms, adds another layer of difficulty. Without streamlined participation structures, tailored incentives, and metrics that reflect the scale and responsiveness of data centers, many existing demand response programs may be ill-suited to the operational realities of modern data centers.

Table 1. Key Data Center Terms

Term	Definition
AI workload	A broad category encompassing computational tasks related to machine learning, natural language processing, generative AI, deep learning, and other AI-driven applications.
AI-specialized data center	Typically developed by hyperscalers, this type of facility is optimized for AI workloads and relies heavily on high-performance graphics processing units (GPUs) and advanced central processing units (CPUs) to handle intensive computing demands.
Computational load	A category of electrical demand primarily driven by computing and data processing activities, ranging from general-purpose computing to specialized AI model training, cryptographic processing, and high-performance computing (HPC).
Conventional data center	A facility that could range from a small enterprise-run server room to a large-scale cloud data center that handles diverse non-AI workloads, including file sharing, transaction processing, and application hosting. These facilities are predominantly powered by CPUs.
Conventional workload	A diverse array of computing tasks typically handled by CPUs, including file sharing, transaction processing, application hosting, and similar operations.
Cryptomine	A dedicated server farm optimized for high-throughput operations on blockchain networks, typically focused on validating and generating cryptocurrency.
Hyperscalers/hyper-scale data centers	Large, well-capitalized cloud service providers that build hyperscale data centers to achieve scalability and high performance at multihundred megawatt scale or larger (Howland 2024b , Miller 2024).
Inferencing	The ongoing application of an AI model, where users prompt the model to provide responses or outputs. According to EPRI, inferencing represents 60% of an AI model's annual energy consumption (Aljbour and Wilson 2024).
Model training	The process of developing and training AI models by processing vast amounts of data. Model training accounts for 30–40% of annual AI power consumption and can take weeks or months to complete (Aljbour and Wilson 2024).

Rethinking Data Centers with AI-Driven Flexibility

Limited documentation of commercial data center participation in demand response has reinforced a perception that these facilities' demands are inherently inflexible loads. A variety of recent developments in computational load profiles, operational capabilities, and broader market conditions, however, suggest that a new phase of opportunity and necessity is emerging.

In a July 2024 memo on data center electricity demand, the SEAB recommended the Department of Energy prioritize initiatives to characterize and advance data center load flexibility, including the development of a “flexibility taxonomy and framework that explores the financial incentives and policy changes needed to drive flexible operation” (SEAB 2024). Building on these recommendations, EPRI announced a multi-year Data Center Flexible Load Initiative (DCFlex) in October 2024 with an objective “to spark change through hands-on and experiential demonstrations that showcase the full potential of data center operational flexibility and facility asset utilization,” in partnership with multiple tech companies, electric utilities, and independent system operators (Walton 2024a).¹⁰

The central hypothesis is that the evolving computational load profiles of AI-specialized data centers facilitate operational capabilities that are more amenable to load flexibility. Unlike the many real-time processing demands typical of conventional data center workloads, such as cloud services and enterprise applications, the training of neural networks that power large language models and other machine learning algorithms is deferrable. This flexibility in timing, often referred to as *temporal flexibility*, allows for the strategic scheduling of training as well as other delay-tolerant tasks, both AI and non-AI alike. These delay-tolerant tasks are also referred to as *batch processing* and are typically not user-prompted (AWS 2025).

This temporal flexibility complements the developing interest in *spatial flexibility*, the ability to dynamically distribute workloads across one or multiple data centers in different geographic locations, optimizing resource utilization and operational efficiency. As stated by EPRI in a May 2024 report, “optimizing data center computation and geographic location to respond to electricity supply conditions, electricity carbon intensity, and other factors in addition to minimizing latency enables data centers to actively adjust their electricity consumption ... some could achieve significant cost savings—as much as 15%—by optimizing computation to capitalize on lower electric rates during off-peak hours, reducing strain on the grid during high-demand periods” (EPRI 2024). For instance, having already developed a temporal workload shifting system, Google is seeking to implement spatial flexibility as well (Radovanović 2020).

In addition to temporal and spatial flexibility, other temporary load reduction methods may also enable data center flexibility. One approach is dynamic voltage and frequency scaling, which reduces server power consumption by lowering voltage or frequency at the expense of processing speed (Moons et al. 2017; Basmadjian 2019; Basmadjian and de Meer 2018). Another is server optimization, which consolidates workloads onto fewer servers while idling or shutting down underutilized ones, thereby reducing energy waste (Basmajian 2019; Chaurasia et al. 2021). These load reduction methods are driven by advances in virtual workload management, made possible by the “virtualization” of hardware (Pantazoglou et al. 2016).

¹⁰ Pointing to EPRI's new DCFlex Initiative, Michael Liebreich noted in a recent essay, “For instance, when they see how much it costs to work 24/7 at full power, perhaps data-center owners will see a benefit to providing some demand response capacity...” (Liebreich 2024).

Finally, temperature flexibility leverages the fact that cooling systems account for 30% to 40% of data center energy consumption (EPRI 2024). For instance, operators can increase cooling during midday when solar energy is abundant and reduce cooling during peak evening demand.¹¹ While these methods may be perceived as uneconomic due to potential impacts on performance, hardware lifespan, or SLAs, they are not intended for continuous use. Instead, they are best suited for deployment during critical hours when grid demand reduction is most valuable.

Beyond peak shaving, data centers also hold potential to participate in ancillary services, particularly those requiring rapid response, such as frequency regulation. Studies have described how data centers can dynamically adjust workloads to provide real-time support to the grid, effectively acting as “virtual spinning reserves” that help stabilize grid frequency and integrate intermittent renewable resources (McClurg et al. 2016; Al Kez et al. 2021; Wang et al. 2019). This capability extends beyond traditional demand response by providing near-instantaneous balancing resources (Zhang et al. 2022).

Three overarching market trends create further opportunities for load flexibility now than in the past. The first is constrained supply-side market conditions that raise costs and lead times for the interconnecting large inflexible loads, when speed to market is paramount for AI developers. The second is advancements in on-site generation and storage technologies that have lowered costs and expanded the availability of cleaner and more commercially viable behind-the-meter solutions, increasing their appeal to data center operators (Baumann et al. 2020). The third is the growing concentration of computational load in colocated or hyper-scale data centers—accounting for roughly 80% of the market in 2023—which is lending scale and specialization to more sophisticated data center operators. These operators, seeking speed to market, may be more likely to adopt flexibility in return for faster interconnection (Shehabi et al. 2024; Basmadjian et al. 2018). The overarching trends underpinning this thesis are summarized in Table 2.

An important consideration for future data center load profiles is the balance between AI-specialized data centers focused on model development and those oriented toward inferencing. If fewer AI models are developed, a larger proportion of computing resources will shift toward inferencing tasks, which is delay-intolerant and variable (Riu et al. 2024). According to EPRI, training an AI model accounts for 30% of its annual footprint, compared to 60% for inferencing the same model (EPRI 2024).

In the absence of regulatory guidance, most advancements in data center flexibility to date are being driven by voluntary private-sector initiatives. Some hyperscalers and data center developers are taking steps to mitigate grid constraints by prioritizing near-term solutions for load flexibility. For example, one such company, Verrus, has established its business model around the premise that flexible data center operations offer an effective solution for growth needs (SIP 2024). Table 3 highlights additional initiatives related to facilitating or demonstrating data center flexibility.

¹¹ Cooling demand for servers is inherently dependent on server workloads. Therefore, reducing workloads saves on cooling needs as well.

Table 2. Trends Enabling Data Center Load Flexibility

Category	Legacy	Future
Computational load profile	- Conventional servers with CPU-dominated workloads (Shehabi et al. 2024) - Real-time, delay-intolerant, and unscheduled processing (e.g., cloud services, enterprise apps) - Low latency critical	- AI-specialized servers with GPU or tensor processing unit (TPU)-favored workloads (Shehabi et al. 2024) - Greater portion of delay-tolerant and scheduled machine learning workloads (model training, non-interactive services) - Higher share of model training affords greater demand predictability - Highly parallelized workloads (Shehabi et al. 2024)
Operational capabilities	- Minimal temporal load shifting - Minimal spatial load migration - High proximity to end users for latency-sensitive tasks - Reliance on Tier 2 diesel generators for backup - Limited utilization of on-site power resulting from pollution concerns and regulatory restrictions (Cary 2023)	- More robust and intelligent temporal workload shifting (Radovanović et al. 2022) - Advanced spatial load migration and multi-data center training (D. Patel et al. 2024) - Flexibility in location for model training - Backup power diversified (storage, renewables, natural gas, cleaner diesel) - Cleaner on-site power enables greater utilization
Market conditions	- Minimal electric load growth - High availability of T&D network headroom - Standard interconnection timelines and queue volumes - Low supply chain bottlenecks for T&D equipment - Low capacity prices and forecasted overcapacity - High cost of clean on-site power options - Small-scale “server room” model	- High electric load growth - Low availability of T&D network headroom - Long interconnection timelines and overloaded queues - High supply chain bottlenecks for T&D equipment - High capacity prices and forecasted undercapacity (Walton 2024b) - Lower cost of clean on-site power options (Baranko et al. 2024) - Data center operations concentrating in large-scale facilities and operators

Table 3. Implementations of Computational Load Flexibility

Category	Examples
Operational flexibility	- Google deployed a “carbon-aware” temporal workload-shifting algorithm and is now seeking to develop geographic distribution capabilities (Radovanović 2020). - Google data centers have participated in demand response by reducing non-urgent compute tasks during grid stress events in Oregon, Nebraska, the US Southeast, Europe, and Taiwan (Mehra and Hasegawa 2023). - Enel X has supported demand response participation by data centers in North America, Ireland, Australia, South Korea, and Japan, including use of on-site batteries and generators to enable islanding within minutes (Enel X 2024). - Startup companies like Emerald AI are developing software to enable large-scale demand response from data centers through recent advances in computational resource management to precisely deliver grid services while preserving acceptable quality of service for compute users
On-site power	Enchanted Rock, an energy solutions provider that supported Microsoft in building a renewable natural gas plant for a data center in San Jose, CA, created a behind-the-meter solution called Bridge-to-Grid, which seeks to provide intermediate power until primary service can be switched to the utility. At that point, the on-site power transitions to flexible backup power (Enchanted Rock 2024, 2025).
Market design and utility programs	- ERCOT established the Large Flexible Load Task Force and began to require the registration of large, interruptible loads seeking to interconnect with ERCOT for better visibility into their energy demand over the next five years (Hodge 2024). - ERCOT’s demand response program shows promise for data center flexibility, with 750+ MW of data mining load registered as CLRs, which are dispatched by ERCOT within preset conditions (ERCOT 2023a). - PG&E debuted Flex Connect, a pilot that provides quicker interconnection service to large loads in return for flexibility at the margin when the system is constrained (Allsup 2024, St. John 2024).
Cryptomining	A company generated more revenue from its demand response participation in ERCOT than from Bitcoin mining in one month, at times accommodating a 95% load reduction during peak demands (Riot Platforms 2023).

ANALYSIS OF CURTAILMENT-ENABLED HEADROOM

In this section we describe the method for estimating the gigawatts of new load that could be added to existing US power system load before the total exceeds what system planners are prepared to serve, provided that load curtailment is applied as needed. This serves as a proxy for the system’s ability to integrate new load, which we term *curtailment-enabled headroom*.¹² We first investigated the aggregate and seasonal load factor for each of the 22 investigated balancing authorities, which measures a system’s average utilization rate. Second, we computed the curtailment-enabled headroom for different assumptions of ac-

¹² SEAB proposed a similar term, *available flex capacity*, in its July 2024 report [Recommendations on Powering Artificial Intelligence and Data Center Infrastructure](#).

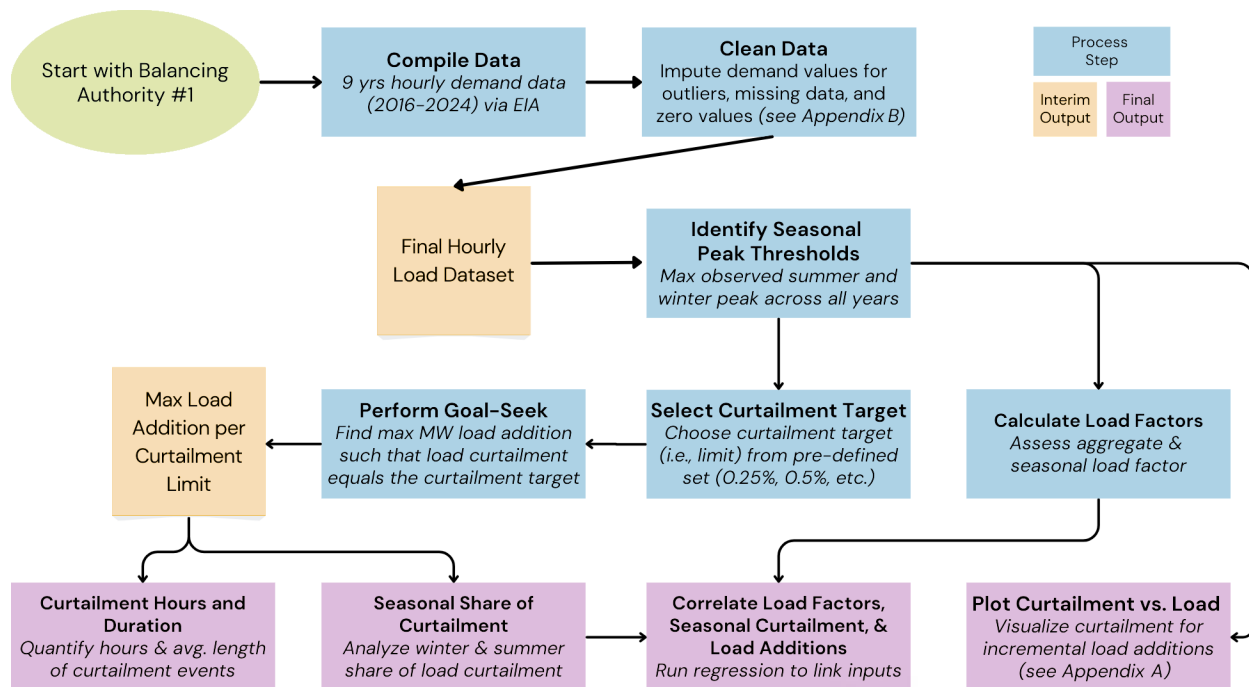
ceptable new load curtailment rates. In this context, *curtailment* refers to instances where the new load temporarily reduces its electricity draw—such as by using on-site generation resources, shifting load temporally or spatially, or otherwise reducing operations—to ensure system demand does not exceed historical peak thresholds. Third, we quantified the magnitude, duration, and seasonal concentration of the load curtailment for each balancing authority. Finally, we examined the correlation between load factor, seasonal curtailment, and max potential load additions. This process is summarized in [Figure 3](#).

Data and Method

Data

We considered nine years of hourly load data aggregated for each of the 22 balancing authorities, encompassing seven RTO/ISOs,¹³ eight non-RTO Southeastern BAs,¹⁴ and seven non-RTO Western BAs.¹⁵ Together, these balancing authorities represent 744 of the approximate 777 GW of summer peak load (95%) across the continental United States. The dataset, sourced from the EIA Hourly Load Monitor (EIA-930), contains one demand value per hour

Figure 3. Steps for Calculating Headroom and Related Metrics



¹³ CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP.

¹⁴ DEC; DEP; DEF; DESC; FPL; Santee Cooper, SCP; Southern Company (SOCO); and TVA. Note the different BA codes used by EIA: DUK for DEC, CPLE for DEP, SCEG for DESC, FPC for DEF, and SC for SCP. Also note that Southern Company includes Georgia Power, Alabama Power, and Mississippi Power. A complete [list of abbreviations and their definitions](#) can be found at the end of the paper.

¹⁵ AZPS, BPA, PACE, PACW, PGE, PSCO, and SRP. Note that EIA uses the code BPAT for BPA. A complete [list of abbreviations and their definitions](#) can be found at the end of the paper.

and spans January 1, 2016, through December 31, 2024.¹⁶ Data from 2015 were excluded because of incomplete reporting.¹⁷ The dataset was cleaned to identify and impute values for samples with missing or outlier demand values (see details in [Appendix B](#)).

Determining Load Additions for Curtailment Limits

An analysis was conducted to determine the maximum load addition for each balancing authority that can be integrated while staying within predefined curtailment limits applied to the new load. The load curtailment limits (0.25%, 0.5%, 1.0%, and 5.0%) were selected within the range of maximum curtailment caps for existing interruptible demand response programs.¹⁸ The analysis focused on finding the load addition volume in megawatts that results in an average annual load curtailment rate per balancing authority that matches the specified limit. To achieve this, a goal-seek technique was used to solve for the load addition that satisfies this condition,¹⁹ for which the mathematical expression is presented in [Appendix C](#). The calculation assumed the new load is constant and hence increases the total system load by the same gigawatt volume hour-by-hour. To complement this analysis and visualize the relationship between load addition volume and curtailment, curtailment rates were also calculated across small incremental load additions (i.e., 0.25% of the BA's peak load).

Load Curtailment Definition and Calculation

Load curtailment is defined as the megawatt-hour reduction of load required to prevent the augmented system demand (existing load + new load) from exceeding the maximum seasonal system peak threshold (e.g., see [Figure 4](#)). Curtailment was calculated hourly as the difference between the augmented demand and the seasonal peak threshold. These hourly curtailments in megawatt-hours were aggregated for all hours in a year to determine the total annual curtailment. The curtailment rate for each load increment was defined as the total annual curtailed megawatt-hours divided by the new load's maximum potential annual consumption, assuming continuous operation at full capacity.

Peak Thresholds and Seasonal Differentiation

Balancing authorities develop resource expansion plans to support different peak loads in winter and summer. To account for variation, we defined seasonal peak thresholds for each balancing authority. Specifically, we identified the maximum summer peak and the maximum winter peak observed from 2016 to 2024 for each balancing authority.²⁰ These thresholds serve as the upper limits for system demand during their respective seasons, and all

¹⁶ Additional detail on EIA's hourly load data collection is available at <https://www.eia.gov/electricity/gridmonitor/about>.

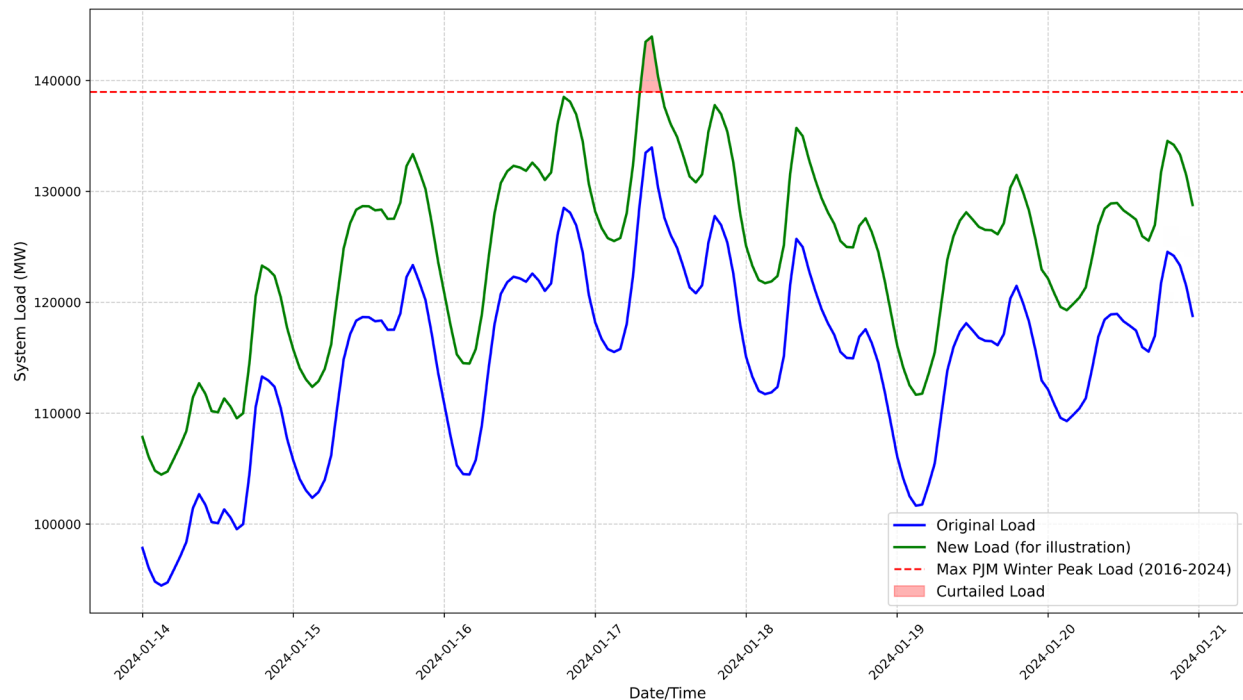
¹⁷ Fewer than half of the year's load hours were available, making the data unsuitable for inclusion.

¹⁸ For example, PG&E's and Southern California Edison's Base Interruptible Programs limit annual interruption for registered customers to a maximum of 180 hours (2.0% of all annual hours) or 10 events per month.

¹⁹ The goal-seek approach was implemented using Python's `scipy.optimize.root_scalar` function from the SciPy library. This tool is designed for solving one-dimensional root-finding problems, where the goal is to determine the input value that satisfies a specified equation within a defined range.

²⁰ To identify the max seasonal peak load, summer was defined as June–August, while winter encompassed December–February. In a few cases, the BA's seasonal peak occurred within one month of these periods (AZPS winter, FPL winter, CAISO summer, CAISO winter), which were used as their max seasonal peak. To account for potential (albeit less likely) curtailment in shoulder months, the applicable summer peak was applied to April–May and September–October and the winter peak to November and March.

Figure 4. Illustrative Load Flexibility in PJM



megawatt-hours that exceeded these thresholds was counted as curtailed energy. This seasonal differentiation captures the distinct demand characteristics of regions dominated by cooling loads (summer peaks) versus heating loads (winter peaks).

Year-by-Year Curtailment Analysis

Curtailment was analyzed independently for each year from 2016 to 2024. This year-by-year approach captures temporal variability in demand patterns, including the effects of extreme weather events and economic conditions. For each year, curtailment volumes were calculated across all load addition increments, resulting in a list of annual curtailment rates corresponding to each load increment. To synthesize results across years, we calculated the average curtailment rate for each load addition increment by averaging annual curtailment rates over the nine years. This averaging process smooths out year-specific anomalies and provides an estimate of the typical system response to additional load. This analysis was also used to calculate the average number of hours of curtailment for each curtailment limit and the seasonal allocation of curtailed generation.²¹ We also assessed the magnitude of load curtailment required during these hours as a share of the new load's maximum potential draw to calculate the number of hours when 90%, 75%, and 50% or more of the load would still be available.

²¹ Consistent with the curtailment analysis, summer was defined as June–August and winter as December–February. For BAs located on the Pacific coast (BPA, CAISO, PGE, PACE, PACW), November was counted as winter given the region's unique seasonal load profile.

Figure 5. Load Factor by Balancing Authority and Season, 2016–2024

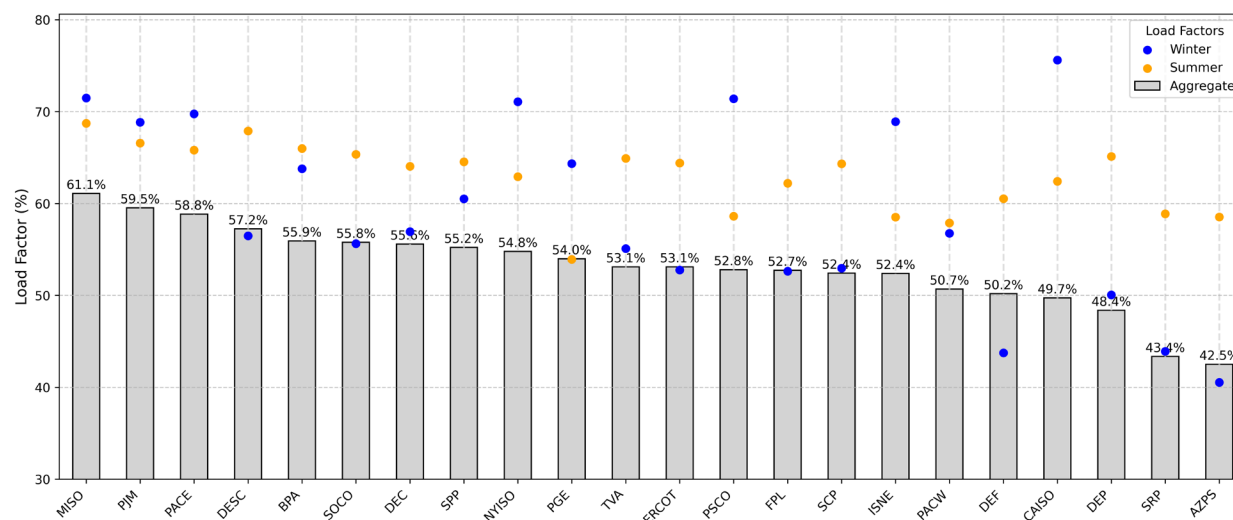
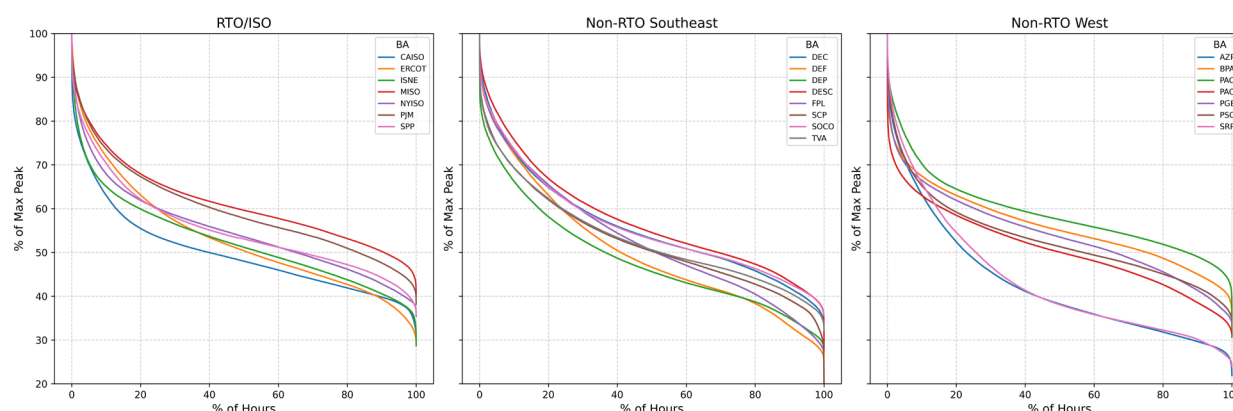


Figure 6. Load Duration Curves by Balancing Authority, 2016–2024



Results

Load Factor

In examining data for 22 balancing authorities, we found that aggregate load factors ranged between 43% to 61% (Figures 5 and 6), with an average and median value of 53%. The BAs with the lowest aggregate load factors were those in the desert southwest, Arizona Public Service Company (AZPS) and Salt River Project Agricultural Improvement and Power District (SRP). In terms of seasonal load factor, defined here as the average seasonal load as a share of seasonal maximum load (i.e., not as a share of the maximum all-time system load), winter load factors were notably lower than summer. The average and median winter load factor was 59% and 57% respectively, compared to 63% and 64% for summer. A majority of the balancing authorities had higher summer load factors (14) than winter (8).

Headroom Volume

Results show that the headroom across the 22 analyzed balancing authorities is between 76 to 215 GW, depending on the applicable load curtailment limit. This means that 76 to 215 GW of load could be added to the US power system and yet the total cumulative load would remain below the historical peak load, except for a limited number of hours per year

Figure 7. Headroom Enabled by Load Curtailment Thresholds, GW

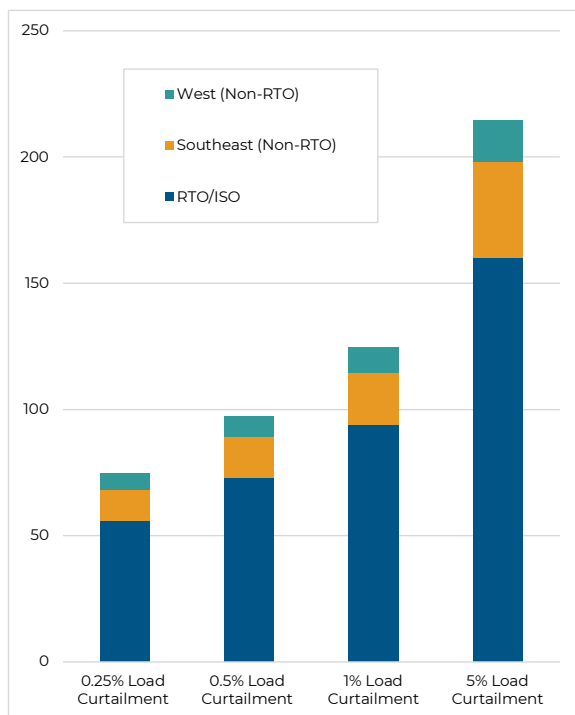


Figure 8. Headroom Enabled by 0.5% Load Curtailment by Balancing Authority, GW

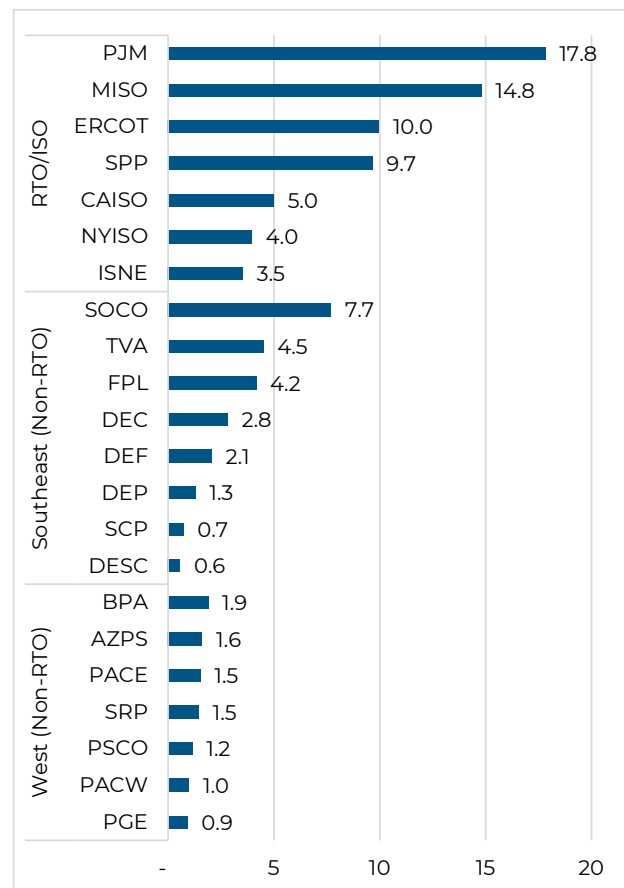
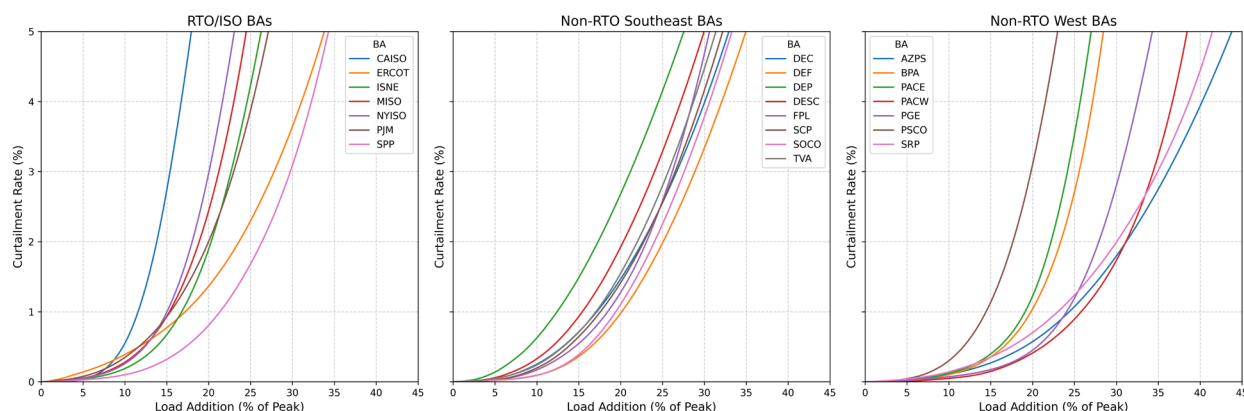


Figure 9. Load Curtailment Rate Due to Load Addition, % of System Peak



when the new load would be unserved. Specifically, 76 GW of headroom is available at an expected load curtailment rate of 0.25% (i.e., if 0.25% of the maximum potential annual energy consumption of the new load is curtailed during the highest load hours, or 1,643 out of 657,000 GWh). This headroom increases to 98 GW at 0.5% curtailment, 126 GW at 1.0% curtailment, and 215 GW at 5.0% curtailment (Figure 7). Headroom varies by balancing authority (Figure 8), including as a share of system peak (Figure 9). The five balancing authorities with the highest potential volume at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW. Detailed plots for each balancing authority, including results for each year, can be found in Appendix A.

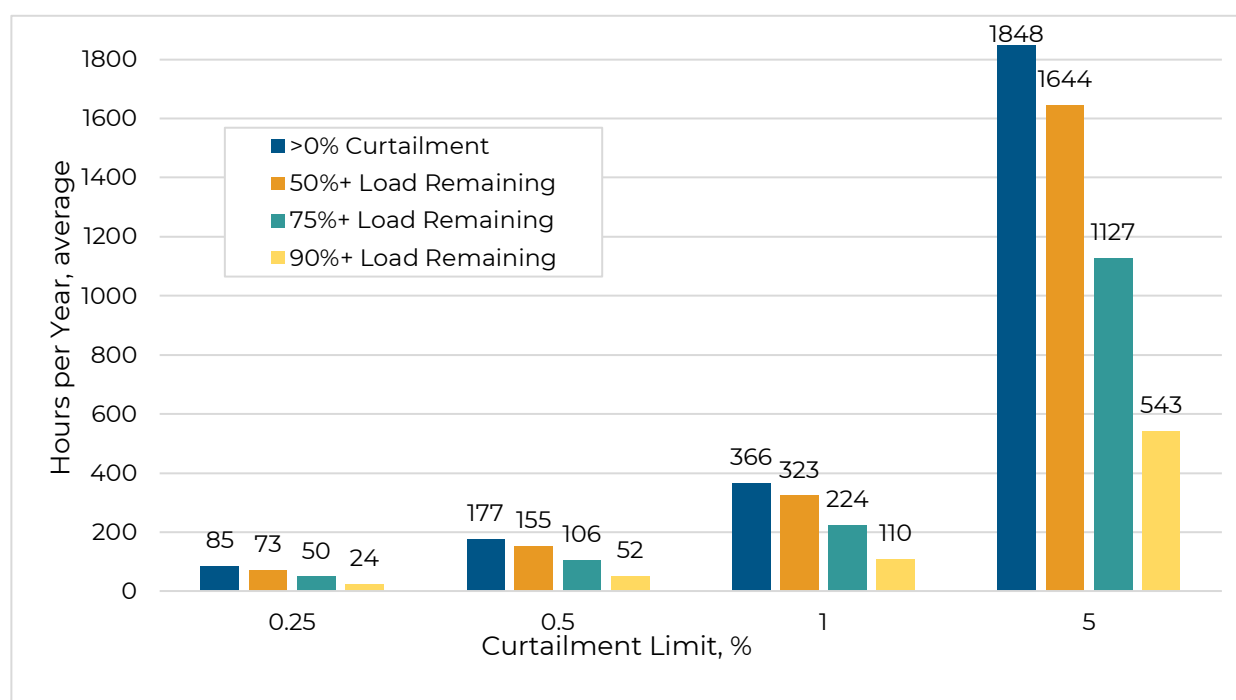
Curtailment Hours

A large majority of curtailment hours retain most of the new load. Most hours during which load reduction is required entail a curtailment rate below 50% of the new load. Across all 22 BAs, the average required load curtailment times are 85 hours under the 0.25% curtailment rate (~1% of the hours in a year), 177 hours under the 0.5% curtailment rate, 366 hours under the 1.0% curtailment rate, and 1,848 hours under the 5.0% curtailment rate (i.e., ~21% of the hours). On average, 88% of these hours retain at least 50% of the new load (i.e., less than 50% curtailment of the load is required), 60% of the hours retain at least 75% of the load, and 29% retain at least 90% of the load (see Figure 10).

Curtailment Duration

The analysis calculated the average hourly duration of curtailment events (i.e., the length of time the new load is curtailed during curtailment events). All hours in which any curtailment occurred were included, regardless of magnitude. The results for each balancing authority and curtailment limit are presented in Figure 11. The average duration across BAs was 1.7 hours for the 0.25% limit, 2.1 hours for the 0.5% limit, 2.5 hours for the 1.0% limit, and 4.5 hours for the 5.0% limit.

Figure 10. Hours of Curtailment by Load Curtailment Limit



Seasonal Concentration of Curtailment

The analysis reveals significant variation in the seasonal concentration of curtailment hours across balancing authorities. The winter-summer split ranged from 92% to 1% for CAISO (California Independent System Operator), where curtailment is heavily winter-concentrated, to 0.2% to 92% for AZPS,²² which exhibited a heavily summer-concentrated curtailment profile (Figure 12a).²³

Figure 11. Average Curtailment Duration by Balancing Authority and Curtailment Limit, Hours

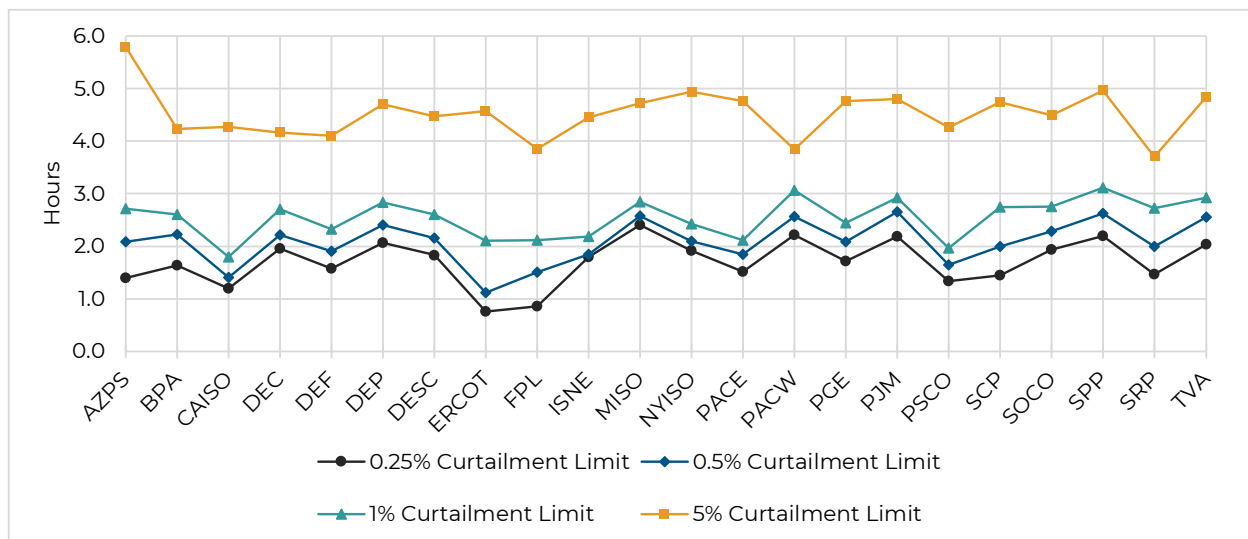
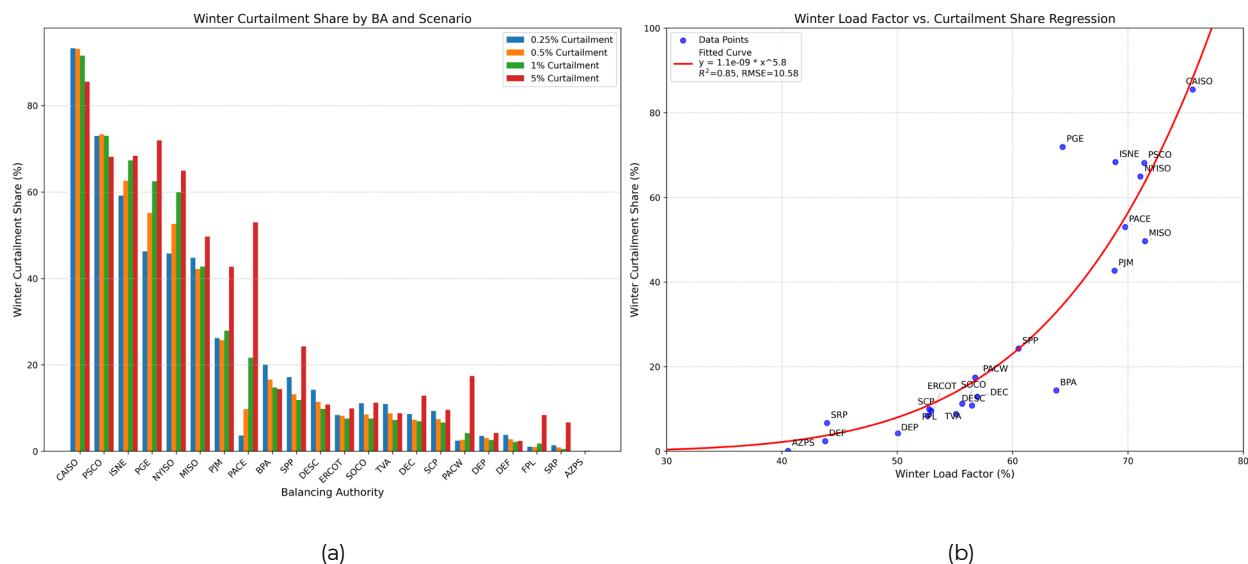


Figure 12. Seasonal Curtailment Analysis



22 Note the remainder of the curtailment occurred in these BAs in shoulder months (i.e., not summer, not winter).

23 These values correspond to the seasonal curtailment concentration for the 1% curtailment limit.

A key observation is the strong correlation between the winter load factor (system utilization during winter months) and the seasonal allocation of curtailment hours ([Figure 12b](#)). BAs with lower winter load factors—indicating reduced system utilization during winter—tend to have greater capacity to accommodate additional load in winter while experiencing a disproportionately higher share of curtailment during summer months. This trend is particularly pronounced in balancing authorities located in the Sun Belt region, resulting in a lower winter concentration of curtailment hours.

While most BAs exhibited relatively stable seasonal curtailment shares across increasing load addition thresholds, some demonstrated notable shifts in seasonal allocation as load additions increased (e.g., PACW, FPL, NYISO, ISO-NE, PACE, PGE). These shifts highlight the dynamic interplay between system demand patterns and the incremental addition of new load.

[Figure 12a](#) illustrates this variability, showcasing the relationship between winter load factor and winter curtailment share across curtailment scenarios.²⁴

Discussion

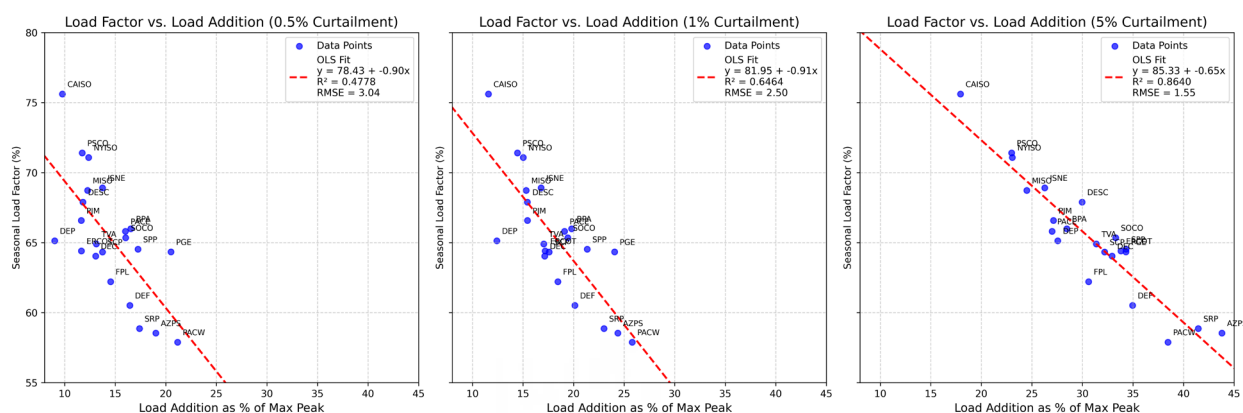
The results highlight that the significant headroom in US power systems—stemming from their by-design low load factors—could be tapped to enable the integration of substantial load additions with relatively low rates of load curtailment. They also underscore substantial variation in flexibility across balancing authorities, driven by differences in seasonal and aggregate load patterns. This variation suggests that seasonal load factors may be strongly linked to how much additional load a balancing authority can integrate without requiring high curtailment rates.

To explore this relationship, we analyzed system load factors in relation to the additional load that each balancing authority could accommodate while limiting the load curtailment rate to 0.5%, 1.0%, and 5.0% (i.e., the load curtailment limit). To allow for meaningful comparison across BAs, the additional load was standardized as a percentage of the BA's historical peak load. To account for whether a balancing authority's curtailment was concentrated in the summer or winter, the seasonal load factor was selected corresponding to the season with the highest share of curtailment.

The analysis revealed that BAs with higher seasonal load factors tended to have less headroom for the load curtailment limits examined ([Figure 13](#)). In simpler terms, systems with higher utilization during their busiest season had less power generation capacity planned to be available that could serve new load without hitting curtailment limits. For example, CAISO, with a seasonal load factor of 76%, could accommodate less additional load compared to PacifiCorp West (PACW) and AZPS, which exhibited lower seasonal load factors and supported larger load additions as a share of peak system load. This relationship grew in statistical significance as the load curtailment limit increased, yielding an R^2 value of 0.48 and an RMSE of 3.04 at the 0.5% curtailment limit, and an R^2 value of 0.86 and an RMSE of 1.55 at the 5% curtailment limit (i.e., 86% of the variation in load addition capacity across balancing authorities can be explained by differences in load factor at a curtailment limit of 5.0%).

²⁴ Note in [Figure 12b](#) that a high-degree polynomial function captures the nonlinear growth in the area under the load curve as curtailed load exceeds a fixed peak threshold. This fit generally aligns with expectations, demonstrating that higher-degree terms are necessary to capture the relationship between load factor and curtailed load.

Figure 13. Load Factor Versus Max Load Addition as Share of Peak Load



These findings emphasize the importance of load factor as a predictor of curtailment-enabled headroom. BAs with more uneven peak seasonal demand—characterized by relatively low system utilization in winter or summer—tend to have greater capacity to integrate new loads with limited curtailment. Conversely, systems with more consistent demand across the winter and summer face tighter limits, as their capacity to absorb additional load is already constrained by elevated baseline usage.

Limitations

This analysis provides a first-order assessment of power generation capacity available for serving new curtailable loads, and hence is an exploration of the market potential for large-scale demand response. The primary focus of the analysis is to ensure that total demand, subject to curtailment limits for new load, stays below the system peak for which system planners have prepared. Other considerations important for planning—such as ensuring adequate transmission capacity, ramping capability, and ramp-feasible reserves, among others—are beyond the scope of this study and therefore the results cannot be taken as an accurate estimate of the load that can be added to the system. Additionally, the analysis assumes the new loads do not change current demand patterns but rather shift the existing demand curves upward, and a more precise assessment of the potential for integration of new loads would require detailed characterization of the temporal patterns of the load. There is significant variation in how system operators forecast and plan for system peaks, accounting for potential demand response, and as a result there will be differences in the methods used to estimate potential to accommodate new load. Despite these limitations, the results presented here signal a vast potential that, even if overstated, warrants further research.

On the other hand, some aspects of this study may have contributed to an underestimation of available headroom. First, the analysis assumes that each BA's maximum servable load in the winter and summer is equivalent to the BA's highest realized seasonal peak demand based on the available historical data. However, the available generation capacity in each balancing authority should materially exceed this volume when accounting for the installed reserve margin. In other words, system operators have already planned their systems to accommodate load volume that exceeds their highest realized peak. Second, the analysis removed outlier demand values in some BAs to avoid using unreasonably high maximum peak thresholds, which would understate the curtailment rates. However, if some of the removed outliers properly represent a level of system load that the system is prepared to serve reliably,

this analysis may have understated the curtailment-enabled headroom. Third, the analysis assumed all new load is constant and hence increases the total system load by the same gigawatt hour-by-hour, which would tend to overstate the absolute level of required gigawatt hour curtailment for a load that is not constant.

Future Analysis

Enhancing this analysis to more accurately assess the capacity to integrate large curtailable load would require addressing the following considerations:

Network Constraints

This analysis does not account for network constraints, which would require a power flow simulation to evaluate the ability of the transmission system to accommodate additional load under various conditions. As such, the results should not be interpreted as an indication that the identified load volumes could be interconnected and served without any expansions in network capacity. While the existing systems are planned to reliably serve their peak loads, this planning is based on the current load topology and the spatial distribution of generation and demand across the transmission network. A large new load could avoid exceeding aggregate peak system demand by employing flexibility, yet still cause localized grid overloads as a result of insufficient transmission capacity in specific areas. Such overloads could necessitate network upgrades, including the expansion of transmission lines, substations, or other grid infrastructure. Alternatively, in the absence of network upgrades, localized congestion could be addressed through the addition of nearby generation capacity, potentially limiting the flexibility and economic benefits of the new load. These factors underscore the importance of incorporating network-level analyses to fully understand the operational implications of large flexible load additions.

Intertemporal Constraints

This analysis does not account for intertemporal constraints related to load and generator operations. For load operations, response times affect system operations and management of operational reserves. Faster response times from flexible loads could alleviate system stress more effectively during peak demand periods, potentially reducing the reliance on reserve capacity. Conversely, slower response times may require additional reserves to bridge the gap between the onset of system imbalances and the load's eventual response. Moreover, the rapid ramp-down of large flexible loads could lead to localized stability or voltage issues, particularly in regions with weaker grid infrastructure. These effects may necessitate more localized network analyses to evaluate stability risks and operational impacts. On the generation side, intertemporal constraints such as ramping limits, minimum up and down times, and startup times can affect the system's ability to integrate fast-response demand. For instance, ramping constraints may restrict how quickly generators can adjust output to align with the curtailment of flexible loads, while minimum uptime and downtime requirements can limit generator flexibility.

Loss of Load Expectation

Peak load is a widely used proxy for resource adequacy and offers a reasonable indicative metric for high-level planning analyses. However, a more granular assessment would incorporate periods with the highest loss of load expectation (LOLE), which represent the times when the system is most likely to experience supply shortfalls. Historically, LOLE periods have aligned closely with peak load periods, making peak load a convenient and broadly

applicable metric. However, in markets with increasing renewable energy penetration, LOLE periods are beginning to shift away from traditional peak load periods. This shift is driven by the variability and timing of renewable generation, particularly solar and wind, which can alter the temporal distribution of system stress. As a result, analyses focused solely on peak load may understate or misrepresent the operational challenges associated with integrating large new loads into these evolving systems.

CONCLUSION

This study highlights extensive potential for leveraging large load flexibility to address the challenges posed by rapid load growth in the US power system. By estimating the curtailment-enabled headroom across balancing authorities, the analysis demonstrates that existing system capacity—intentionally designed to accommodate the extreme swings of peak demand—could accommodate significant new load additions with relatively modest curtailment, as measured by the average number, magnitude, and duration of curtailment hours.

The findings further emphasize the relationship between load factors and headroom availability. Balancing authorities with lower seasonal load factors exhibit greater capacity to integrate flexible loads, highlighting the importance of regional load patterns in determining system-level opportunities. These results suggest that load flexibility can play a significant role in improving system utilization, mitigating the need for costly infrastructure expansion and complementing supply-side investments to support load growth and decarbonization objectives.

This analysis provides a first-order assessment of market potential, with estimates that can be refined through further evaluation. In particular, network constraints, intertemporal operational dynamics, and shifts in loss-of-load expectation periods represent opportunities for future analyses that can offer a deeper understanding of the practical and operational implications of integrating large flexible loads.

In conclusion, the integration of flexible loads offers a promising, near-term strategy for addressing structural transformations in the US electric power system. By utilizing existing system headroom, regulators and market participants can expedite the accommodation of new loads, optimize resource utilization, and support the broader goals of reliability, affordability, and sustainability.

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ABBREVIATIONS

AI	Artificial intelligence
AZPS	Arizona Public Service Company
BA	balancing authority
BPA	Bonneville Power Administration
CAGR	compound annual growth rate
CAISO	California Independent System Operator
CLRs	controllable load resources
CPUs	central processing units
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEP	Duke Energy Progress East
DERs	distributed energy resources
DESC	Dominion Energy South Carolina
EIA	Energy Information Administration
EPRI	Electrical Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERIS	Energy Resource Interconnection Service
FERC	Federal Energy Regulatory Commission's
FPL	Florida Power & Light
GPUs	graphics processing units
ICT	information, and communication technology
ISO-NE	ISO New England
LGIA	Large Generator Interconnection Agreement
LOLE	loss of load expectation
MISO	Midcontinent Independent System Operator
NYISO	New York Independent System Operator
PACE	PacifiCorp East
PACW	PacifiCorp West
PG&E	Pacific Gas and Electric
PGE	Portland General Electric Company
PJM	PJM Interconnection
PSCO	Public Service Company of Colorado
RMSE	Root mean square error
RTO/ISO	Regional transmission organization/independent system operator
SCP	Santee Cooper, South Carolina Public Service Authority
SEAB	Secretary of Energy Advisory Board
SLAs	service-level agreements
SOCO	Southern Company
SPP	Southwest Power Pool
SRP	Salt River Project Agricultural Improvement and Power District
TPU	tensor processing unit
TVA	Tennessee Valley Authority

APPENDIX A: CURTAILMENT-ENABLED HEADROOM PER
BALANCING AUTHORITY

Figure A.1. Curtailment Rate Versus Load Addition by RTO/ISO, MW

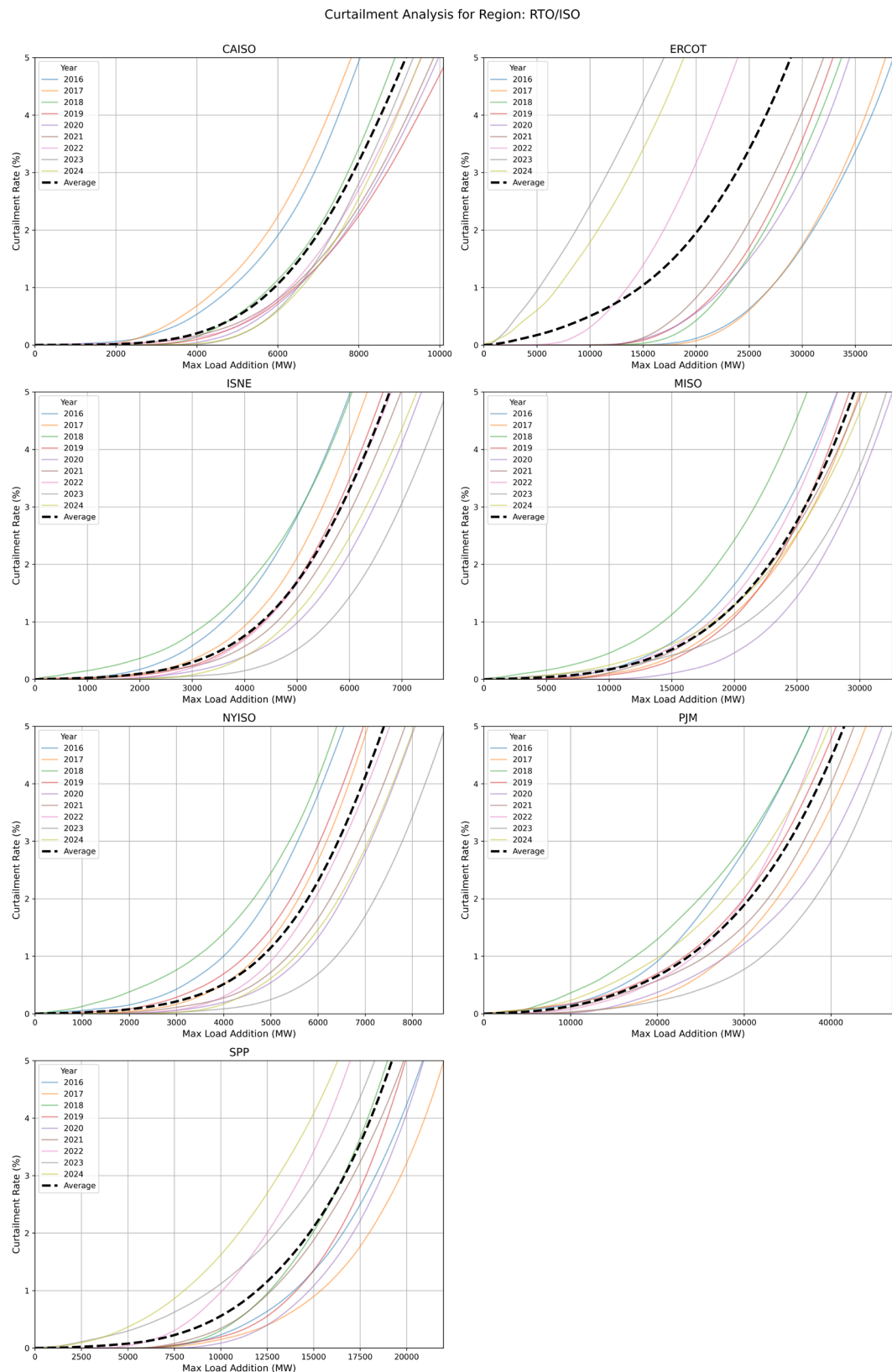


Figure A.2. Curtailment Rate Versus Load Addition by Non-RTO Southeastern Balancing Authority, MW

Curtailment Analysis for Region: Non-RTO Southeast

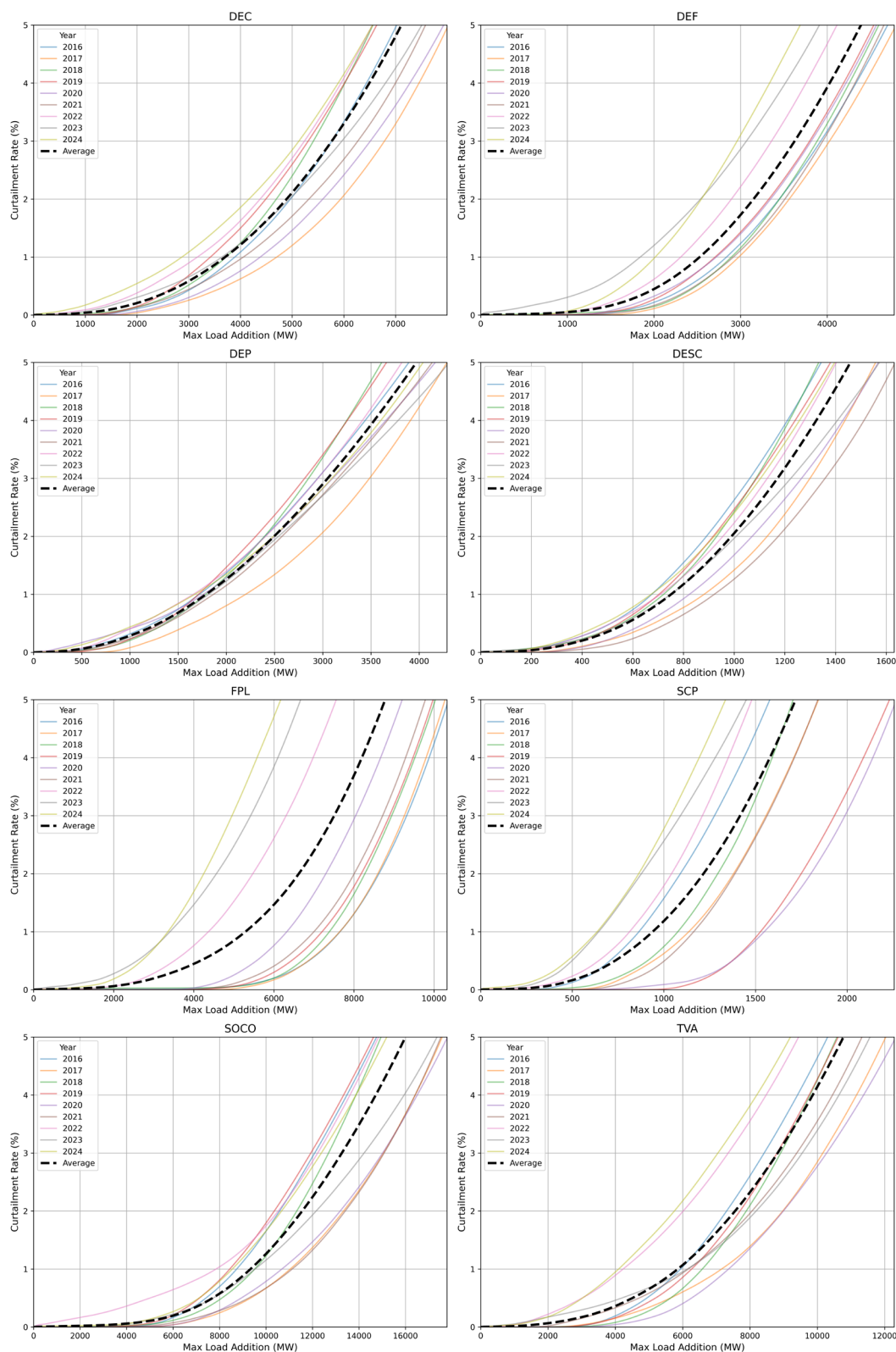
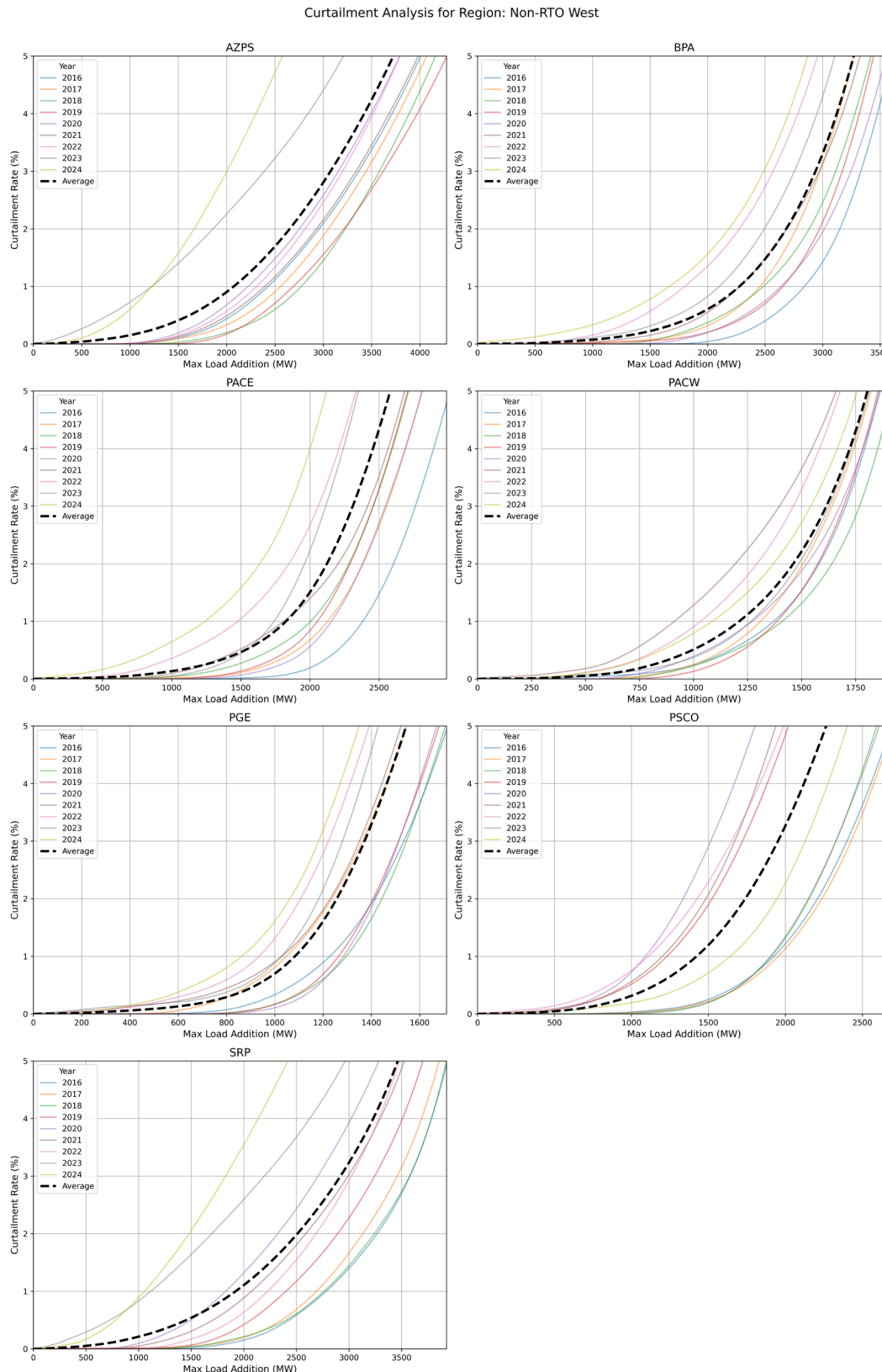


Figure A.3. Curtailment Rate Versus Load Addition by Non-RTO Western Balancing Authority, MW



APPENDIX B: DATA CLEANING SUMMARY

The data cleaning process attempted to improve the accuracy of nine years of hourly load data across the 22 balancing authorities, including the following steps:

1. Data normalization

- **Dates:** Date-time formats were verified to be uniform.
- **Demand data:** Where the balancing authority had an “Adjusted demand” value for a given hour, this value was used, otherwise its “Demand” value was used. The final selected values were saved as “Demand” and a log was kept.
- **BA labels:** Labels were mapped to align with widely used acronyms, including:
 - CPLE → DEP
 - DUK → DEC
 - SC → SCP
 - SWPP → SPP
 - SCEG → DESC
 - FPC → DEF
 - CISO → CAISO
 - BPAT → BPA
 - NYIS → NYISO
 - ERCO → ERCOT

2. Identifying and handling outliers

- **Missing and zero values:** Filled using linear interpolation between adjacent data points to maintain temporal consistency.
- **Low outliers:** Demand values below a predefined cutoff threshold (such as 0 or extremely low values inconsistent with historical data) were flagged. Imputation for flagged low outliers involved identifying the closest non-outlier value within the same balancing authority and time period and replacing the flagged value.
- **Spikes:** Sudden demand spikes that deviated significantly from historical patterns were flagged. Corrections were applied based on nearby, consistent data.
- **Erroneous peaks:** Specific known instances of demand peaks that are outliers (e.g., caused by reporting errors) are explicitly corrected or replaced with average values from adjacent time periods.

3. Data validation:

- Seasonal and annual peak loads, load factors, and other summary statistics were computed and inspected to ensure no unexpected results. Max peaks were compared to forecasted peaks collected by FERC to ensure none were out of range.
- Logs summarizing corrections, including the number of spikes or outliers addressed for each balancing authority, were saved as additional documentation.

APPENDIX C: CURTAILMENT GOAL-SEEK FUNCTION

Mathematically, the function can be expressed as

$$\frac{1}{N} \sum_{y=1}^N \left(\frac{Curtailment_y(L)}{L \cdot 8,760} \cdot 100 \right) = CurtailLimit$$

where

L	=	load addition in MW (constant load addition for all hours)
N	=	total number of years in the analysis (2016–2024)
$Curtailment_y(L)$	=	curtailed MWh for year y at load addition L
$L \cdot 8,760$	=	maximum potential energy consumption of the new load operating continuously at full capacity
$CurtailLimit$	=	predefined curtailment limit (e.g., 0.25%, 0.5%, 1.0%, or 5.0%).

For each hour t in year y , the curtailment is defined as

$$Curtailment_t(L) = \max(0, Demand_t + L - Threshold_t)$$

where

L	=	load addition being evaluated in MW
$Demand_t$	=	system demand at hour t in MW
$Threshold_t$	=	seasonal peak threshold applicable for hour t in MW (i.e., the maximum winter or summer peak across all years)

These hourly curtailments are aggregated to find the total annual curtailment

$$Curtailment_y(L) = \sum_{t \in T_y} Curtailment_t(L)$$

where

T_y	=	all hours in year y .
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Replacing $Curtailment_y(L)$ in the original formula, the integrated formula becomes

$$\frac{1}{N} \sum_{y=1}^N \left(\frac{\sum_{t \in T_y} \max(0, Demand_t + L - Threshold_t)}{L \cdot 8,760} * 100 \right) = CurtailLimit$$

Question:

3. Refer to the Company's Voluntary Green Pricing (VGP) offering "External Power Purchase Agreement (PPA) Option" for large customers.

- a. How many customers currently utilize this program?
- b. How much energy in (MWh) is provided through this program?
- c. How many MW of (i) wind, (ii) solar, or (iii) other renewable resources have been developed as a result of this program?
- d. How many customer applications to participate in this program has the Company received in each of the past five years?
- e. Has the Company received any applications from data center customers to participate in its VGP program?
- f. Does the Company believe that the VGP program could be used by data center customers to access new clean energy and capacity? Please explain why or why not.
- g. How does the Company vet proposals from customers who wish to utilize the VGP program?

Response:

- a. 0
- b. 0
- c. 0
- d. 0
- e. 0
- f. This offering could benefit data centers if they are in Consumers' electric service territory and meet the requirements to participate in the VGP.
- g. Per the Company's tariff "(1) Customer Eligibility Available to Full Service Customers adding new Primary Voltage load not previously served by the Company prior to their enrollment in the Program. New Primary Voltage load for existing customers is considered incremental load served by the Company at 2,400 volts or higher, which was not previously served by the Company, as measured by the customer's average Maximum Demand for the previous 24 months. The customer's aggregated new Maximum Demand must be in excess of 1,000 Kilowatts with a minimum of a 70% load factor or at the discretion of the Company. A

customer may aggregate their accounts or meters to reach this requirement. Customers participating under this option may provide the renewable energy from their owned solar or wind renewable facilities or obtain solar or wind renewable energy from a third party provider selected by the participating customer. There is no minimum or maximum generation requirement for the customer's selected source of renewable energy. The customer's renewable energy must be generated from a facility physically located within MISO and certified as 100% renewable energy. The Company may act as the administrator for the customer's renewable PPA under a separate energy management contract. To participate in the Program, the customer shall provide documentation to include total subscribed generation and contract term for the External PPA."

Witness: Laura M. Connolly

Date: June 5, 2025

**STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION**

In the Matter of the Application of	)	
Consumers Energy Company for Ex Parte	)	
Approval of Certain Amendments to Rate	)	Case No. U-21859
GPD.	)	

PROOF OF SERVICE

I hereby certify that a true copy of the foregoing *Direct Testimony and Exhibits of Saad Siddique on behalf of The Ecology Center, The Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar (collectively the “Clean Energy Organizations” or “CEO”)* was served by electronic mail upon the following Parties of Record, Thursday, June 12, 2025.

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