U.S. House Committee on Energy and Commerce
Full Committee
"Converting Energy into Intelligence: the Future of AI Technology, Human Discovery, and American Global Competitiveness."
April 9, 2025
Documents for the Record

1. Report entitled "The Electricity Supply Bottleneck on U.S. AI Dominance" March 2025, submitted by Chairman Guthrie.
2. Letter to Chairman Guthrie and Ranking Member Pallone from the Digital Energy Council, April 9, 2025, submitted by Chairman Guthrie.
3. NERC report entitled "2024 Long-Term Reliability Assessment" December 2024, submitted by Chairman Guthrie.
4. CATO Institute Policy Analysis report entitled "The Budgetary Cost of the Inflation Reduction Act's Energy Subsidies" March 11, 2025, submitted by Chairman Guthrie.
5. Letter from SAFE to Chairman Guthrie and Ranking Member Pallone, submitted by the Majority.
6. Report from the Environmental & Energy Law Program at Harvard Law School entitled "Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power" March 2025, submitted by Rep. Castor.
7. Article from Reuters entitled "Exclusive: Micron to impose tariff-related surcharge on some products from April 9, sources say" April 8, 2025, submitted by Rep. DeGette.
8. Article from PoliticoPro entitled "Why Trump's tariff and tax policies could derail efforts to boost US power supply" April 8, 2025, submitted by Ranking Member Pallone.

MARCH 2025

The Electricity Supply Bottleneck on U.S. AI Dominance

By Cy McGeady, Joseph Majkut, Barath Harithas, and Karl Smith

It is now well understood that the rapid technological progress of artificial intelligence (AI) has profound energy sector implications. AI technology is effectively the result of three inputs: chips, data, and electricity. This paper focuses on electricity on the basic premise that electricity supply is the most acutely binding constraint on expanded U.S. computational capacity and, therefore, U.S. AI dominance.

This paper starts with a survey of demand-side forecasts. It then highlights data on the geographic distribution of data center development currently underway in the United States, the supply-side dynamics underway in response to demand growth, and challenges to meeting this new demand. The role of coal, gas, renewables, and nuclear power in meeting new demand are each assessed. The central principle for understanding these developments is speed-to-power, or the measure of how fast a potential data center site can access the electricity needed to power its stock of chips.

Speed-to-power should likewise be used to organize federal policymakers' approach to permitting policy and use of emergency authorities in the near term. On the other hand, five years from now is tomorrow in the power sector. A severe near-term supply crunch must not distract policymakers from the need for long-term thinking in the electricity sector. Numerous long-standing policy challenges in the power sector deserve renewed attention, including gas-electric coordination, interregional seams management, and improved cost efficiency in transmission planning. This paper closes by proposing several new policies and authorities that contribute to these issues, but which are primarily organized around establishing U.S. electricity supply dominance in a bid to advance U.S. AI leadership. A new era of electricity-intensive economic growth has arrived, and the need for strategic thinking in the electricity sector has never been greater.

CSIS | CENTER FOR STRATEGIC & INTERNATIONAL STUDIES

The Age of AI and Electricity Demand

The basic reality of a surge in data center-based electricity demand has been confirmed by a wide range of work from the private sector, civil society, and national labs. Recent **estimates** from the Lawrence Berkeley National Laboratory (LBNL) place electricity consumption by data centers at 176 terawatt-hours (TWh) in 2023, representing 4.4 percent of total U.S. electricity demand.

Table 1: Data Center Electricity Consumption Forecasts

Group	Forecast Subject	Current Value	Forecast Value	Growth Value
CSIS (author's analysis)	U.S. AI data centers	4 gigawatts (GW) in 2024	84 GW by 2030	2,100 percent
LBNL	U.S. data centers	20 GW in 2023	74 to 132 GW by 2028	370–660 percent
RAND	Global AI data centers	11 GW in 2024	68 GW by 2027 and 327 GW by 2030	618 percent
SemiAnalysis	Global data centers	49 GW in 2023	96 GW by 2026	196 percent
BCG	Global data centers	60 GW in 2023	127 GW by 2028	212 percent
McKinsey	Global data centers	55 GW in 2023	171 to 219 GW by 2030	311–398 percent
Goldman Sachs	Global data centers (excluding crypto)	400 TWh in 2023	1,040 TWh by 2030	260 percent

Source: Authors' analysis.

The range in future estimates of AI power demand highlights the complex set of factors—hardware technology, algorithmic progress, commercial strategy, economy-wide uptake of AI, and power sector capacity—that interact to create uncertainty over the exact trajectory of electricity demand from the computation sector. The sector is attracting enormous volumes of **capital investment** and competition is driving rapid innovation throughout the ecosystem. Developments including sudden efficiency jumps such as those achieved by **DeepSeek** or progress on **distributed data center training** capabilities are to be expected. Such developments will impact specific firms, commercial strategies, and technology paths, but are indicative of continued sectoral scaling rather than signs of imminent sectoral crash correction. Policy should see past short-term perturbations and grasp that growth is the definitive long-term direction of AI technology and computation demand.

Despite the dynamic nature of the current moment, policymakers can be certain a new era of electricity demand growth has arrived. Data from SemiAnalysis, which provides best-in-industry tracking of chip production, chip orders, and individual data center developments, shows that **over 80 GW of data center capacity** under various stages of development could be brought online in the United States by 2030. These facilities could consume over 800 TWh per year, which alone represents a 3 percent annual growth in total U.S. power demand. The biggest risk to this forecast is in the electric power sector's ability to serve this demand.

The U.S. electric power sector is facing a stunning and sudden paradigm shift. For roughly two decades, top-line national electricity consumption has **stagnated**, growing at a compound annual growth rate of nearly 0 percent since 2007. The electric power industry as a whole has been decelerating since the 1970s; recent decades of near-zero demand growth follow decades more of steadily declining growth rates. Multiple generations of commercial strategy, regulatory norms, and policy debates have been conditioned by this seemingly inexorable trajectory and are now out of date.

This **story** extends beyond AI. Electricity demand is also growing from other electricity-intensive industries like semiconductor fabrication and battery manufacturing. The broad political consensus to reindustrialize the U.S. economy will drive growth in energy-intensive industries like mining, minerals processing, metallurgy, and beyond. A deep technological trend toward electrification means industry, along with the transport and heating sectors, is growing more electricity-intensive each year. Successfully navigating a new era of electricity demand growth will deliver the United States a lasting advantageous position in the **technological commanding heights** of the future.

The Future of Data Center Demand

Today, access to electricity supply is the binding constraint on expanded computational capacity and therefore on continued U.S. leadership in AI. This fact is demonstrated by a total focus among data center developers on "speed-to-power." Speed-to-power is the time it takes a potential data center site to receive access to electricity supply. In Northern Virginia—the nation's and the world's largest data center market—speed-to-power is growing worse, as data centers now face electricity supply **wait times** up to 7 years.

For data center developers, speed-to-power far outweighs other factors like the price of power or access to land. Even access to high-end chips is a secondary concern, as hyperscalers cannot access enough electricity supply to power their existing stocks of chips. An example of the high value placed on speed-to-power relative to price is the xAI **data center facility** in Memphis, Tennessee, which, due to long wait times for grid-supplied power, instead rented road-portable gas-fired generators which operate at far higher unit costs than large grid-connected combined cycle power plants. The race for progress on the AI frontier and the rapid growth in computational demand for AI services make speed-to-power the central principle driving data center investment in the near term.

Data from SemiAnalysis again provides **clear indications on the scale and distribution** of this demand boom. Virginia, already the world's largest data center market, is on track to see enormous growth over the next five years and will remain the country's most important computing cluster. Despite severely constrained power supply data centers continue to expand in the area **because** of access to key internet infrastructure such as fiber networks, latency, and other provision of service considerations. By 2030, the region could **host** 20 GW of data center capacity. A central policy objective for federal AI strategy should be to improve speed-to-power for this computing cluster.

Table 2: Data Center Boom by Region (Active and Planned Capacity, GW)

Region	2024	2030	Growth
Southeast	13	49	36
West	12	43	31
Midwest	7	30	23
Northeast	1	3	2
U.S. Total	32	124	92

Source: "Datacenter Industry Model," SemiAnalysis, February 2025, https://semianalysis.com/datacenter-industry-model/.

Those data centers that are not constrained by service provision concerns, such as data centers dedicated to model training, are seeking out new geographies that offer faster speed-to-power. SemiAnalysis shows that **twenty-nine states** are slated to see over 100 percent growth in hosted data center capacity. States like **Louisiana** and **Mississippi** currently host no data center capacity and have recently attracted multi-gigawatt datacenter investments. Despite a flight to new geographies, computing capacity will remain regionally concentrated. By 2030 just nine states will host 70 percent of the nation's data center capacity. Virginia and Texas are the standouts, projected to together represent 34 percent of the nation's data center capacity in 2030.

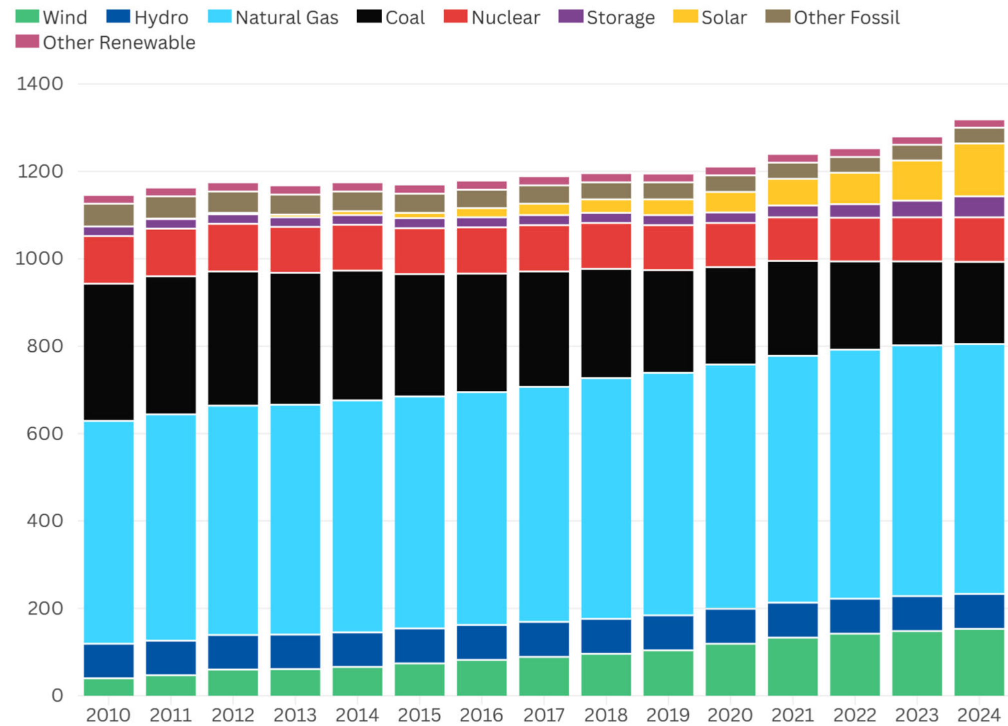
Texas, the Midwest, Southeast, and Southwest stand out as new regions attracting large volumes of data center investment. In contrast, California and the Northeast stand out for low levels of data center development. Data center investment is flowing where state-level power sector policy, permitting, and land-use issues are permissive to a rapid buildout of new generation needed to power new data centers.

The State of National Generation Base

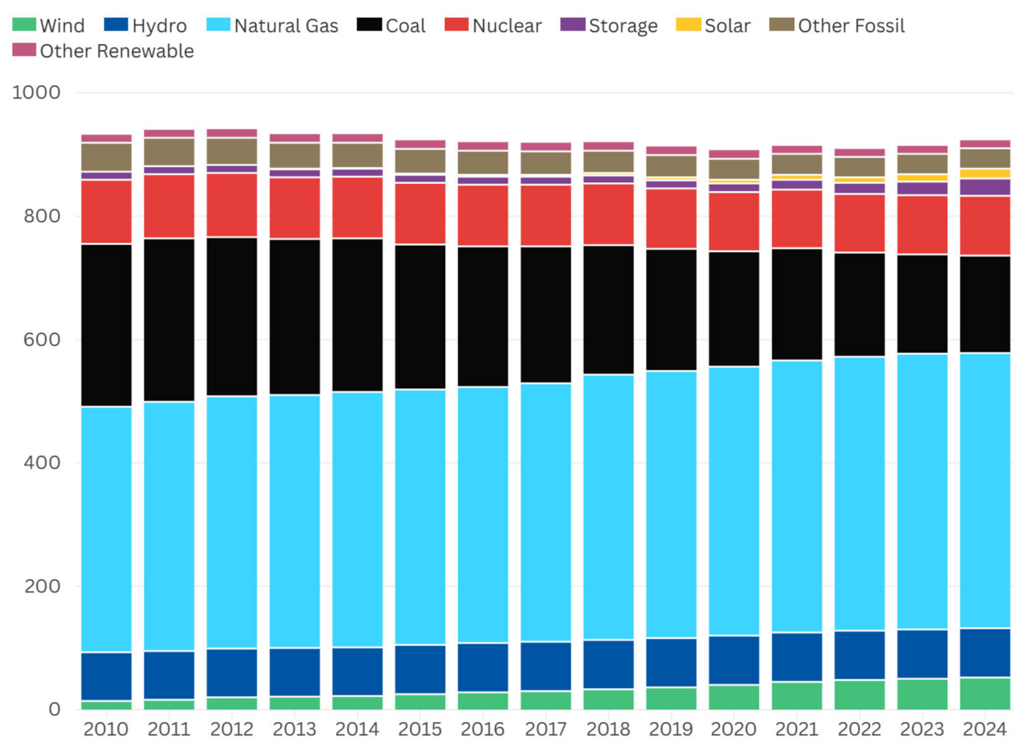
How did electricity supply suddenly emerge as a binding constraint on data center expansion and AI progress in 2025? After all, Energy Information Administration (EIA) **data** shows that since 2010, nameplate generation capacity in the United States has grown by 172 GW to a total of 1,318 GW.

The non-firm nature of wind and solar generation makes nameplate capacity a deceptive measure of the nation's generation base. To maintain reliability, utilities and grid operators account for and plan using the effective capacity of generation resources, which accounts for the likely availability of each class of generation technology during peak demand scenarios. An example is the **Effective Load Carrying Capacity** (ELCC) measures used by PJM, the largest power grid in the nation, in its capacity markets, which are designed to ensure sufficient generation resources to meet demand over the long term. Applying the PJM ELCC factors to the nameplate capacity dataset results in a dramatically different picture of the national generation mix.

Figure 1: U.S. Generation Mix-Nameplate Capacity vs. Effective Capacity (GW)



Source: Author's calculations; Preliminary Monthly Electric Generator Inventory, U.S. Energy Information Administration, February 2025, https://www.eia.gov/electricity/data/eia860m/.



Source: Author's calculations; Preliminary Monthly Electric Generator Inventory, U.S. Energy Information Administration, February 2025, https://www.eia.gov/electricity/data/eia860m/.

Though this is a rough adjustment—in reality each utility and grid operator employs distinct capacity adjustment factors—the overall effect is directionally correct. The total effective capacity of the U.S. generation base has stagnated since 2010, and it may have even declined. Coal-fired generation with high ELCC ratings (84 percent) has been replaced by low ELCC resources like onshore wind (34 percent) and solar (13 percent). Even dispatchable gas-fired generation (78 percent) has a lower rating than coal and nuclear (95 percent) because of fuel supply and gas-electric coordination **issues** during winter storms.

A stagnant base of effective capacity has only been possible (i.e., compatible with the reliability imperative) because it coincided with a period of near-zero load growth at the national level. And yet, even small amounts of demand growth combined with a flat or declining base of effective capacity equates to thinning reserve margins. This is a finding compatible with **repeated reporting** from the North American Electric Reliability Corporation (NERC) and reports from regional grid operators like **MISO** and **PJM**, which all warn of thinning generation reserve margins. A series of capacity shortfall incidents in California (**2020, heat wave**, Western Interconnection), Texas (**2021, Winter Storm Uri**, Electric Reliability Council of Texas (ERCOT) Interconnection), and the southeast (**2022, Winter Storm Elliot**, Eastern Interconnection) have demonstrated that increasingly narrow capacity margins are leading to reliability failures.

On a national level, there is effectively no "spare capacity." Though regional pockets and individual generators where spare capacity exists, these are exceptions to the broader national trend. Today, every new gigawatt of data center demand must be met with matching new gigawatts of effective capacity sited within the borders of the same reliability planning region. The past failure to grow effective capacity explains why a focus on speed-to-power necessarily follows from the data center boom and AI technology race.

The Coal Option

The sudden emergence of electricity demand growth has definitively slowed the rate of decline in the coal fleet. Major utilities have **proposed** integrated resource plans (IRPs) with **suspended or delayed** coal retirement schedules. **Soaring capacity prices** in PJM have improved prospects for merchant-owned coal plants. Rising market **valuations** for coal plant operators further illustrate the improved economic outlook for existing coal.

As of December 2024, the U.S. coal fleet is **composed** of over 400 units representing 188 GW of capacity. As recently as 2023, **expectations** were for 70-100 GW of this capacity to retire by 2035. The Environmental Protection Agency's (EPA) modeling for its 2024 **greenhouse gas emissions rule** indicated 150 GW or more of retirements were possible by 2035. But the Trump administration's goal to **repeal** the EPA greenhouse gas rule, combined with improving market signals and shifting utility IRPs, means these rapid retirement scenarios are unlikely to materialize. In fact, the Trump administration's exploration of using emergency authorities to keep coal plants open is unlikely to be broadly necessary.

In the near-term speed-to-power era, delayed coal retirements make the problem of supplying new AI demand more manageable. The retirement of a coal plant creates a "backfill" requirement for new generation that delivers the same amount of effective generation capacity. Preserving reliability is the first priority for utilities and reliability authorities, so new generation capacity is generally allocated to the backfill requirement before new demand customers like data centers. In short, backfill competes with new demand for a limited supply of new generation projects and must always win. Therefore, slowed retirement schedules mean that most new generation resources can be allocated to serve new data center demand, a result which increases speed-to-power for AI data centers.

Improved near-term prospects notwithstanding, the coal fleet is aging and remains in terminal decline. Over 130 GW of the capacity (70 percent of the fleet) is at least 40 years old. Age and declining economic competitiveness with gas and renewables has pushed down utilization; in 2023 the coal fleet nationwide produced at a 42 percent **capacity factor**, down from 61 percent in 2014. Near-term demand growth may drive increased utilization at certain plants, but increased wear and tear brings forward large maintenance investments, which in many cases will bring forward ultimate retirement dates.

At the strategic level, the delayed coal retirement strategy buys time but shifts the challenge to the future. Retirements will slow down in the near term and then accelerate again in the mid-2030s and beyond. As the large effective capacity contribution of the coal fleet rapidly retires in the 2030s, a smooth and low-cost deployment schedule for new replacement generation is essential to maintain reliability. Policymakers need to start planning and enabling investment today to ensure this future.

Gas Boom

A boom in natural gas generation is clearly underway in the U.S. power sector today. Data from the EIA **shows** nearly 30 GW of new gas generations in various stages of development will come online by 2030. A more comprehensive **survey** of development plans from S&P shows over a hundred projects totaling more than 70 GW is possible. The scale of the boom is not without precedent: Over 220 GW of capacity was deployed in the five-year period from 2001 to 2005.

Utilities and independent power producers (IPPs) are turning to gas generation to serve new demand because there is no other technology that brings as much effective capacity online, in as fast a timeline, with as much siting flexibility, under such a manageable financial profile.

Gas generation can be sited at or very near data center sites, which creates grid stability benefits and reduces overall transmission system investment costs. Meta's new 2 GW **data center** in Richland Parish, Louisiana, will host two combined cycle gas plants. Some gas generation will be deployed alongside data centers fully islanded from the grid, a model which avoids interconnection costs and delays. ExxonMobil has **announced** plans to develop 1.5 GW of fully islanded gas generation fitted with carbon capture technology and co-located with data centers, most likely sited in Texas. Siting of gas generation is somewhat constrained by the need to access pipelines for fuel. Ease of access to existing networks and easier permitting explains the strong growth in gas deployment in Texas and the Southeast. With natural gas production booming and prices at or near all-time lows, access to fuel volumes at reasonable prices is a nonissue.

The gas generation boom is creating upstream supply chain constraints. Orders for new gas turbines are rapidly piling up at major manufacturers like **GE**, **Mitsubishi**, and **Siemens**, with these firms reporting order books with delivery now stretching out past 2028. Though construction of a new gas plant can take as little as a year, with these backlogs, a project placing an equipment order today is unlikely to come online until 2030 or beyond. This order backlog inevitably includes a huge number of U.S.

projects at later stages of planning and development, so gas deployment will continue the coming years, but scaling growth rates will be a challenge.

The Solar and Storage Portfolio Play

The gas generation boom goes hand in hand with a boom in solar and storage deployment. Across different states, markets, and policy paradigms, the current economics of power generation technology favor a hybrid portfolio of gas, storage, and renewables. Gas generation delivers the effective capacity necessary to ensure demand can be served under all scenarios. Renewables, particularly solar, deliver ultra-low marginal cost electricity production on rapid deployment timelines, which improves overall portfolio costs, improves speed-to-power, and reduces the emissions profile of projects. Battery storage adds value by smoothing operations through renewable ramping periods, delivers ancillary services like frequency regulation at low cost, and brings option value that improves the overall economic and reliability profile of a generation portfolio.

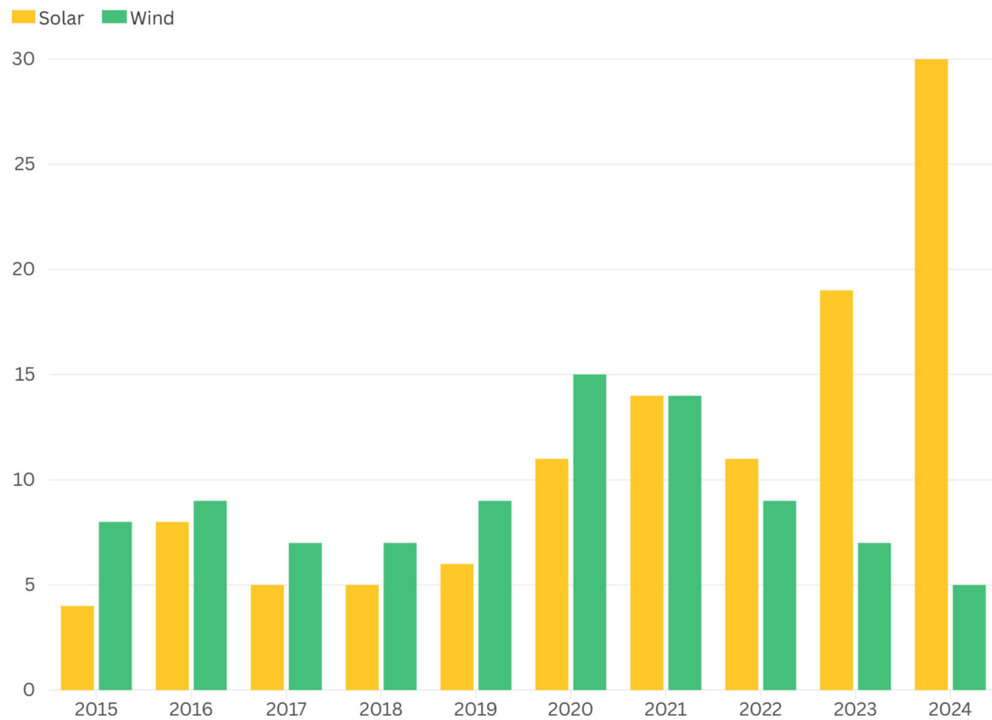
Dominion Energy, the utility that serves the Northern Virginia data center market, provides an illustrative example. Its 2024 IRP includes **plans** for 6 GW of gas, alongside 12 GW of solar, 6 GW of offshore wind, and 4.5 GW of storage by 2039. Plans from other major integrated utilities like **Georgia Power** and **Duke Energy** also display a similar portfolio approach.

Solar is rapidly coming to dominate the overall market for new generation capacity and increasingly overshadows wind's contribution. A record 30 GW of solar were **deployed** nationally in 2024; in contrast, wind deployment was at its weakest since 2014, at just 5 GW. Transmission system congestion in the nation's best wind resource regions (e.g., the Great Plains) creates long and costly interconnection processes and is a major obstacle to new wind generation. Meanwhile, solar paired with storage, directly on-site or in portfolio, has been shown to greatly **improve** the project value to electricity buyers, which has made such projects more attractive to developers and financiers relative to stand-alone wind development.

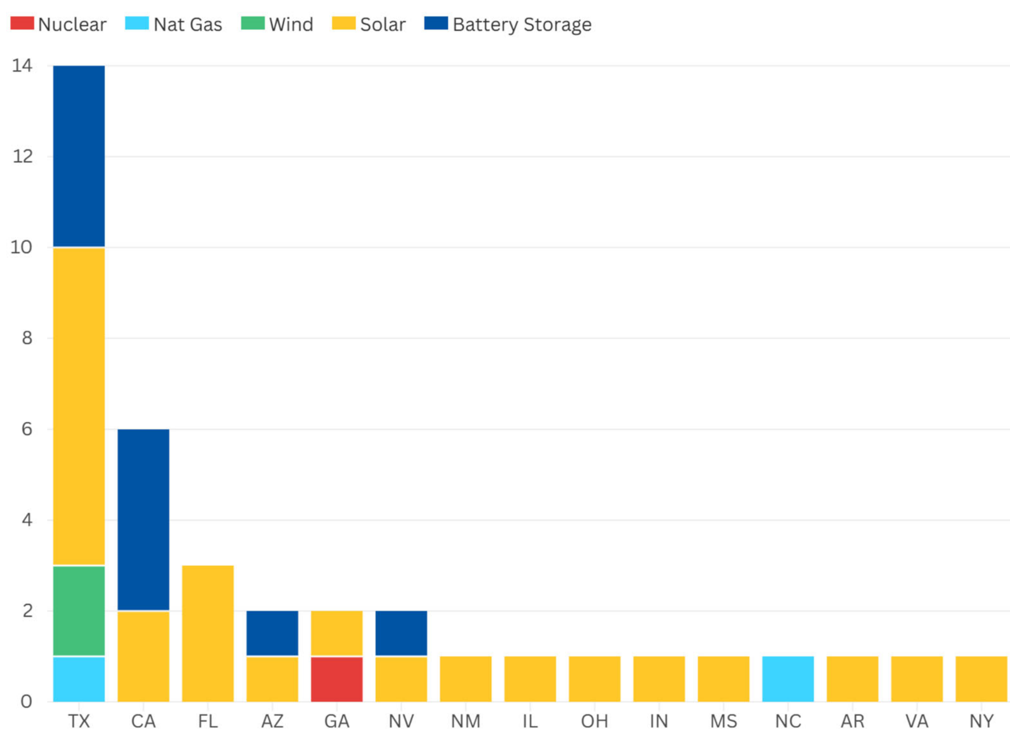
The overwhelming dominance of Texas in deploying new generation resources, with solar the dominant category, must be noted. Texas attracts investment with a low-barriers permitting environment, fast access to grid connection under the ERCOT "**connect-and-manage**" model, and plentiful land. In Texas, which is served via a competitive market rather than an integrated utility, interconnection queue data indicates incredible interest in developing solar and storage. As of January 2025, 28 GW of gas, 38 GW of wind, 153 GW of solar, and 165 GW of storage are **active** in various stages of the ERCOT interconnection queue. While many of these projects are speculative and unlikely to come to fruition, the distribution of volumes is a useful indicator: Solar and storage dominate the project development pipeline, though small behind-the-meter or fully islanded gas generation projects are excluded and would likely shift the balance slightly.

Available information about specific data centers shows that companies are building renewables to meet demand. Meta's recently announced 2 GW data center in Louisiana will be **backed** by 1.5 GW of **solar procurement** along with natural gas plants. Project Stargate, a **joint venture** between OpenAI, Oracle, and SoftBank, is anticipating data centers at the 5 GW scale. The project's first site in Abilene, Texas, will be supplied by **solar and storage projects** developed elsewhere in the ERCOT grid alongside on-site gas generation.

Figure 2: Diverging Fortunes for Wind and Solar, by Year and by State



Source: Preliminary Monthly Electric Generator Inventory, U.S. Energy Information Administration, February 2025, https://www.eia.gov/electricity/data/eia860m/.



Source: Preliminary Monthly Electric Generator Inventory, U.S. Energy Information Administration, February 2025, https://www.eia.gov/electricity/data/eia860m/.

Turning Point for Nuclear

The next five years will be dominated by deployment of large volumes of gas generation, solar, and storage. What, then, is the role of nuclear power? A series of commercial deals announced in 2024 signaled that nuclear power will also be a winner in the new era of electricity demand growth. But nuclear remains—for now—a fundamentally slow-moving technology whose primary contribution will be post-2030.

The first and now easily overlooked shift in nuclear power is the certain end to the era of premature nuclear retirements based on economics. As **recently** as 2021, over 10 GWs of reactors were planning for or at risk of early retirement. The Palisades nuclear plant was shuttered in May 2022 just months prior to the release of ChatGPT in November of 2022, which in many ways marks the start of the AI-fueled electricity demand boom.

The first pathway to "new" nuclear power is through reactor restarts. Microsoft's **deal** with Constellation, the largest nuclear operator in the country, to restart Three Mile Island Unit 1 will bring 835 MW of high effective capacity generation to southeastern Pennsylvania in 2028. Importantly, the plant is located very close to the Northern Virginia computing cluster. The Palisades project in Michigan (800 MW) is slated to **return to service** as early as October 2025. A restart at the Duane Arnold nuclear reactor in Iowa (600 MW) is under **consideration**, but no final investment has been announced. Capacity from nuclear restarts is structurally limited however because all other retired reactors are too far along in decommissioning to be brought back online.

Uprates at existing nuclear plants can deliver relatively small volumes of incremental new capacity. A **recent deal** between the U.S. General Services Administration (GSA) and Constellation will help finance uprates at existing nuclear plants. In 2023, Constellation **announced** an $800 million uprate investment at two Illinois nuclear plants that will deliver an additional 135 MW of capacity. In total, the Nuclear Energy Institute **estimates** that upwards of 3 GW of new uprates are possible.

Truly new nuclear projects will commence in the next five years. Several first-of-a-kind reactor projects are slated to finish by roughly 2030. These include Department of Energy (DOE)-**supported** advanced reactor designs developed by firms like **Kairos**, **X-Energy**, and **TerraPower**. These smaller-capacity and easily replicated (in theory) designs have the potential to radically alter the economics of nuclear energy from that of megaproject to something comparable to a gas-fired combined cycle. It is this theory of scaling that has attracted investment from tech firms like **Google** and **Amazon**. But policymakers should not expect perfect performance from day one from first-of-a-kind reactors. There will **inevitably** be early operational learning and design iteration periods before true commercial scaling commences. Significant contributions to the national generation mix from this segment can only be expected by the mid-2030s.

New large reactor projects, most likely utilizing the AP1000 reactor technology deployed at the recently completed Vogtle plants, are increasingly possible but not certain. New hyperscale data center clusters with demand up to 5 GW in size would appear to be natural matches for large-scale reactors. Abroad, the United Arab Emirates' **deployment** of gigawatt-scale reactors is attracting data center investment from hyperscalers and is a model for the strategic value of large-scale nuclear in the AI era.

Despite a clear economic and strategic value proposition, the sheer size of the capital investment and cost-overrun risks loom large. The **final cost** of the recently completed Vogtle 3 and 4 reactor projects was $32 billion, which includes $18 billion of cost overruns. Illustrative of the challenge are recent **comments** from the CEO of Entergy, which operates multiple nuclear reactors, on prospects for new nuclear projects: "The size of the potential plant could be bigger than the entire balance sheet of the existing company, which just gives you a sense for the scale of risk that might be there for that operating company."

Absent significant policy or commercial developments, it is not certain that new large-scale reactor projects will emerge. Restarting construction at the half-finished V.C. Summer reactor project in South Carolina is a **possibility**. Additional units at Vogtle in Georgia, reactors 5 and 6 at the plant, is likewise a plausible option. Stephen Kuczynski, former Southern Company nuclear chairman who oversaw the completion of Vogtle 3 and 4, **recently characterized** construction risk as "exaggerated" given the enormous and expensive lessons learned at the Vogtle projects. New entities like **the Nuclear Company** propose to innovate on the commercial model as an integrated project developer of large-scale. Combined with growing state-level policymaker **interest**, this indicates a plausible path forward, but more policy assistance may be needed.

Regardless, even in a best-case **construction scenario**, a new AP1000 project will take six years or more, resulting in the earliest possible contribution to the resource mix starting in the early 2030s. A steady scaling of nuclear supply chains, workforce, and technology maturation is crucial for nuclear to play a role in smoothing coal (and existing nuclear) retirements in the 2030s and beyond. Nuclear will play a limited role in the near-term speed-to-power era but could deliver enormous economic and strategic value to the nation over the medium and long term.

Federal Electricity Policy in an AI Era

What can the federal government do to ensure that the United States can power data centers and win the global race for AI? Federal policy must both address the near-term speed-to-power moment and set a long-term course toward a lasting advantage in electricity supply. In the speed-to-power era, permitting, siting, and other permissions are key areas where federal policy can help, while the generation investment choices will largely be made by the private sector and state policy makers (and rely mostly on a gas, solar, and storage expansion).

But in a sector defined by long lead times and long-lived infrastructure—a new nuclear plant or high-voltage transmission line can comfortably last 80 years—policymakers must keep an eye on the future. Investment decisions during the next several years will determine whether the U.S. grid in the 2030s and beyond allows for unconstrained electricity demand growth, at globally competitive prices, with a world-leading reliability profile—or if dramatic load growth leads to instability and internal conflict over a scarce resource.

Federal policy must also work within the framework of energy federalism. Securing U.S. dominance in AI technology is a clear national strategic priority which only federal policymakers are positioned or authorized to pursue. But federal policymakers face a jurisdictional dilemma. Electricity supply—the gating constraint on continued U.S. AI dominance—is primarily the **domain** of state-level authorities. By virtue of the long-standing **Federal Power Act**, authority over retail rates and utility generation investments lies primarily with state policymakers. Rather than radically altering this framework, federal policy should focus on greatly improving the option set for state policymakers.

Lastly, a key area for attention is minimizing cost inflation for existing ratepayers. Electricity prices are rising rapidly, recently **outpacing inflation**. State legislatures and public utility commissions (PUCs) are facing a wave of **utility investment requirements** that translate into increasing rates. Wherever possible, federal policy should enable and encourage policy that lowers costs for generation and grid investment and reduces ratepayer exposure to investment directly tied to data centers. In cases where projects deliver clear national strategic value in the AI race, federal funding should buy down project costs to reduce ratepayer cost inflation.

Enabling the Speed-to-Power Era (2025-2030)

For the power sector, five years away is tomorrow. Demand growth over the next five years will be almost entirely served by projects already under development or construction. The data indicates clearly that generation deployment will be dominated by gas, solar, and storage. In the near-term, federal policy can primarily assist in clearing obstacles to deployment.

EMERGENCY SITING, PERMITTING, AND PLANT RETIREMENT DELAY AUTHORITIES

President Trump has already signed executive orders declaring an **energy emergency** and establishing a new **National Energy Dominance Council**. These authorities should be directed toward improving the permitting environment for generation projects that are under development in an all-of-the above generation strategy. Fast-tracked permitting for the gas midstream, electric transmission, and electric generation projects would support speed-to-power for AI data centers. Support for enhanced geothermal on federal land is crucial for a nascent, but potentially **globally competitive**, American technology.

Most coal power plants that are operating today will likely remain open for the near term based on the new economic and reliability value proposition in the speed-to-power era, independent of the use of emergency authorities. In exceptional cases, the use of emergency authorities may be justified where state policy forces coal plant closures that raise reliability risks. Nonetheless, emergency powers are a short-term solution and should be supplemented with support for new generation that will serve the long-term multi-decadal demand growth challenge (see below).

The Northern Virginia computing cluster should be the primary focus of emergency authorities, as it is the region facing the most severe constraints on data center expansion. The administration should consider fast-tracked permitting for generation resources in the region, including offshore wind under development off the Virginia coast, which will improve speed-to-power for the strategically vital Northern Virginia computing cluster.

Emergency authorities should also target siting approval for late-stage high-voltage transmission projects that, once completed, will create room on the grid for new generation and demand resources. Focus should be paid to transmission projects that improve integration of the Northern Virginia computing cluster with new and existing generation in surrounding states. PJM has approved a series of transmission projects for this express purpose that in many cases are held up by state-siting and permitting hurdles. This authority should also consider transmission projects in the emergent demand clusters in the Midwest, Southeast, and Southwest, which are serving a combination of strategically vital data centers, semiconductor fabrication, and battery manufacturing loads.

CO-LOCATION AND ISLANDING

The focus on speed-to-power has resulted in a strong trend toward co-locating data centers directly on-site alongside power plants. Siting new generation projects alongside new data centers is a widely pursued development strategy that poses no significant policy question. In contrast, siting new data centers alongside existing generation, as **proposed** at the Susquehanna nuclear plant in the PJM market, raises significant reliability and affordability concerns. The Federal Energy Regulatory Commission (FERC) rejected the Susquehanna proposal on narrow technical grounds but has yet to issue a formal, broadly applicable **policy** on the issue.

Numerous merchant-operated nuclear power plants in the 13-state PJM market could likely pursue similar deals if such co-location deals were okayed by the FERC. This path would radically improve speed-to-power for data centers in the mid-Atlantic market but also raise considerable reliability risks. This would in effect look like the sudden retirement of a large amount of generation from the grid without any obligation to bring on new replacement generation resources. Prices in PJM's **capacity market** would soar (if they are **allowed** to), and ratepayer prices would rise in response. The Trump administration needs to weigh the reliability and affordability risks on the one hand versus the race for AI dominance on the other.

A path forward might grant the DOE a time-limited window (e.g., through 2030) to approve co-locating at existing nuclear plants on a case-by-case basis, based on reliability assessments. One option would be to approve such arrangements only if those deals include firm plans and financial commitments to begin construction of equivalent new generation resources. Such plans could include federal support (see below). This could potentially thread the needle between speed-to-power for AI data centers and reliability.

Full physical islanding of power generation and data centers in gigawatt scale or larger "microgrids" is a way to accelerate private capital investment and improve speed-to-power. From a policy perspective this path is **attractive** becomes it carries no financial risk to ratepayers and poses no risk to grid reliability. Federal policy can help by clarifying that these private grids would not be subject to FERC oversight, given that they are purely commercial arrangements between private businesses. It would then lie with state policymakers to legalize such arrangements under state law and establish light-touch PUC oversight.

Building a Strategic Electricity Advantage Era (2030 and Beyond)

Federal policy in the near term can dramatically alter sectoral trajectory in 2030 and beyond for the better in terms of costs, reliability, and global strategic energy advantage. Solar will run into land-use and permitting constraints, especially outside of Texas and east of the Mississippi, where a significant volume of new data center demand is sited. It is unlikely that any state or market will be able to match the rapid interconnection rates achieved in Texas under the connect-and-manage model absent significant, slow, and politically challenging market restructuring.

Gas deployment will face delays and cost increases sourced from the turbine backlog. More importantly, in an age of liquefied natural gas exports, a growing domestic gas burn in the power sector competes with growing high-margin exports for natural gas. The fundamental **basis of energy security is in variety**, and growing reliance on a single fuel source in the power sector—in this case natural gas—eventually veers into overreliance. Though the United States possesses vast natural gas reserves, wellhead prices will eventually climb, and this will directly translate into higher electricity prices. The United States would be wise to cultivate diversity in the electricity sector, which would have the bonus value of freeing up gas volumes for high-margin overseas exports.

With these principles, constraints, and risks in mind, federal policy should focus on developing nuclear power to anchor a long-term global electricity supply advantage that supports AI dominance. Abroad, data center development is increasingly likely to flow to countries with existing or growing nuclear capacity such as China, France, Japan, and the United Arab Emirates. A nuclear-centric AI energy strategy provides the additional benefit of ensuring China does not grow to dominate the global nuclear power market as it already has with solar and storage. Over the last decade, China **built** 27 nuclear reactors compared to two in the United States, and it has another 23 reactors in various stages of construction; the United States is at risk of being left behind. Policymakers should act today to enable a post-2030 power sector that enables reliable, low-cost, demand expansion.

NUCLEAR COMPUTATION HUBS

Nuclear computation hubs would direct federal resources to states interested in both developing new nuclear power and attracting data center investment. A **10-state coalition** launched in February 2025 indicates the growing appetite for a state-led, federally supported model. States want nuclear energy but are reluctant to expose ratepayers to the risk of cost overruns. Coordination challenges hamper an alternative model that brings data center developers together around a multi-plant, multistate investment plan. Nuclear computation hubs roughly modeled after the **DOE's Hydrogen Hubs** program would cut through these hurdles. The **slow development** that has characterized clean hydrogen hubs is primarily a function of limited financial upside and investor appetite in a nascent market. In contrast, nuclear computation hubs would rapidly attract vast amounts of private capital eager to invest in the economic opportunity represented by AI and the boom in computation and electricity demand.

Nuclear computation hub applications would likely be partnerships between state energy offices, data center developer and operators, and a power developer—either an IPP or an investor-owned utility—targeting sites capable of hosting a 2 GW data center and 2 GW or more of nuclear capacity. Sites should also have plausible access to high-voltage transmission and access to additional sources of generation (e.g., gas, solar, geothermal, storage) which can support data center operations while nuclear construction proceeds.

Selected hubs would receive access to federal loan guarantees (under the DOE Loan Programs Office or equivalent authorities), grant funding for pre–Final Investment Decision site development work, federal cost sharing for high-voltage transmission investments needed to connect the cluster to the grid, expedited federal permitting, and, potentially, DOE nuclear offtake (see below). States would be encouraged to establish nuclear and data center workforce development plans for engineers, welders, and electricians, which federal funds could further support. Finally, federal support could be made contingent on states streamlining their permitting processes for energy and infrastructure more broadly.

DOE ANCHOR OFFTAKER AUTHORITY AND NUCLEAR PROCUREMENT TARGET

As part of the Infrastructure Investment and Jobs Act, Congress created a new **anchor tenant authority** which enables the DOE to buy capacity rights (or "offtake") in merchant transmission projects. Anchor tenancy by the federal government enables private transmission projects to secure funding from private capital markets and attract other capacity offtakers, which speeds overall deployment timelines. As other customers crowd in to contract offtake from the new transmission project, the government can surrender or auction off its contracted volumes.

Congress could authorize and fund the DOE to pursue the same model for new nuclear power. In such a model, the DOE, optionally working in consort with a federal Power Marketing Administration or the Tennessee Valley Authority, would enter into power offtake contracts with nuclear project developers. As the construction period proceeds towards commercial operation, offtake capacity can be sold off in part to private firms (hyperscalers, semiconductor fabs, etc.) or transferred to rate-regulated utilities so that the broader rate base can access the benefits of nuclear power at no risk of cost overruns. To protect taxpayers, offtake contracts should be entered into at market rates and terms. Risk sharing should be authorized insofar as it is shared across parties; this authority should not be implemented as a form of cost overrun insurance. A target of contracts supporting 10 GW of new nuclear construction underway by 2030 would radically expand the domestic nuclear construction program and ensure the 2030s are an era of rapid nuclear power growth and U.S. nuclear power leadership at home and abroad.

STRATEGIC ELECTRICITY PRODUCTION SITES ON FEDERAL LANDS

An **executive order** issued by President Biden in the closing days of his administration directed the Department of Defense, the Department of the Interior, and the DOE to identify and prepare federal sites for data center development, leveraging existing infrastructure and streamlined permitting authorities. This order should be recast with a primary focus on identifying sites for nuclear, geothermal, and solar generation. Federal land combined with fast-tracked federal permitting could be attractive for data centers only if the site delivers competitive speed-to-power. The "**three pillars of additionality**" (new clean supply, hourly matching, and deliverability) clean-energy mandate embedded in the Biden administration executive order should be scrapped to allow gas generation to be deployed as part of a portfolio power solution that prioritizes speed and flexibility. Identified sites should be made available for partnership and participation in state-led nuclear computation hubs to improve opportunities for states with large amounts of federal land.

STRATEGIC GRID INVESTMENT

The Infrastructure Investment and Jobs Act appropriated $10.5 billion to the DOE to establish a Grid Resilience and Innovation Partnerships (GRIP) fund. Through two rounds of funding, The Grid Deployment Office has **disbursed** $7.6 billion for 105 projects, including smart grids, renewable energy interconnection, and emergency repair projects in response to Hurricane Helene.

The program's remaining funds should be narrowly focused on high-voltage grid investments that support the strategic goal of rapid data center interconnection. Large hyperscale computing clusters and large generation projects (e.g., combined cycle natural gas or nuclear power plants) both must be sited close to high-voltage transmission. It is no coincidence that Meta's 2 GW Richland Parish data center in Louisiana is sited only a few miles from a branch of the U.S. Southeast's 500 kilovolt (kV) backbone transmission system. Likewise, AEP utilities in Ohio and Illinois are attracting data centers in large part due to the existing 765 kV grid system in the region.

Utilities across the country are proposing **investment** in high-voltage substations and transmission lines to support data center demand growth, and federal dollars should be deployed to reduce or eliminate ratepayer exposure to these strategically vital investments. Unlike generation, the costs of which can be easily assigned to a single large datacenter, grid investments network infrastructure whose costs and benefits are spread widely. Offsetting portions of this AI-based investment with federal dollars is key to reducing costs for ratepayers and advancing the national interest. The remaining $2.4 billion is nowhere near sufficient to accomplish these goals. Congress should consider replenishing and expanding this fund to support the proposed nuclear computation hubs and national energy transmission corridors (see below).

National Interest Energy Transmission Corridors

Interstate energy transmission infrastructure, be it via pipeline or wire, provides broad long-term strategic benefits to the nation. Long-term policy, permitting, and political hurdles to all types of energy transmission infrastructure have undermined energy security and competitiveness.

The existing National Interest Electric Transmission Corridor (NIETC) **authority** should be expanded into a National Interest Energy Transmission Corridor authority that applies to both gas and electric transmission projects. Enabling legislative language should be streamlined to give the secretary of energy wide discernment to identify projects that serve the strategic national interest as set forth by the president. If the federal authority is invoked to site a project based on strategic national interest, then it makes sense that federal funding should likewise be deployed to pay for that national strategic value and reduce or eliminate ratepayer impact. A reformed NIETC authority would require that projects are given access to federal funding via grants (e.g., GRIP funds), low-interest loans (e.g., DOE Loan Programs Office), or anchor tenant contracts. Selected projects should also receive fast-tracked emergency permitting.

This authority could target pipelines and electric transmission projects that improve speed-to-power for existing computation clusters (e.g., Northern Virginia) and emerging computation clusters in the Midwest, Southeast, and Southwest. For example, this authority should be used to authorize and partially fund the **Piedmont Reliability Project in Maryland** which has been approved by PJM but faces political challenges at the state level. This and similar projects will boost desperately needed transmission capacity between the Northern Virgina computing cluster and the Three Mile Island nuclear plant, as well as bolstering access other firm generation resources in Pennsylvania and the Midwest. It could also be used to advance energy transmission projects which support nuclear computation hubs or to deploy pipelines which lower costs and improve reliability in pipeline constrained regions.

Conclusion

For decades, U.S. energy strategy has revolved around U.S. exposure to global oil markets. Abroad, this resulted in a focus on oil-shipping sea lanes, most notably the Persian Gulf. Domestically, this resulted in a focus on energy independence. As an organizing principle, this is increasingly out of date. The United States has been a net energy **exporter** since 2019, and in 2024, it was the world's largest producer of both **oil** and **natural gas**.

The rise of AI has elevated electricity supply to a new level of strategic importance. A new long-term U.S. energy strategy should seek to establish global dominance in electricity supply comparable to the achieved global dominance in the oil and gas sector. The present reality of electricity scarcity that inhibits AI progress should be transformed into a long-term position of global dominance in electricity supply.

Scaling of this sort is achievable: In the decade between 1982 and 1991, U.S. electricity consumption grew by about 800 TWh, and the power sector built 43 nuclear reactors totaling 52 GW of capacity. All of this was accomplished without the aid of any modern digital engineering, manufacturing techniques, or construction technology, let alone AI itself. Whether it is nuclear, gas, solar, storage or geothermal the needed technology exists. Simply put, the engineering and technology challenges associated with meeting AI energy demand are not difficult. The onus is on policymakers to break through the status quo and unleash a future of U.S. electricity supply dominance. ■

Cy McGeady *is a fellow in the Energy Security and Climate Change Program at the Center for Strategic and International Studies (CSIS) in Washington, D.C.* ***Joseph Majkut*** *is director of the Energy Security and Climate Change Program at CSIS.* ***Barath Harithas*** *is a senior fellow in the Economics Program and Scholl Chair in International Business at CSIS.* ***Karl Smith*** *is an economic policy consultant specializing in AI.*

The authors would like to acknowledge the crucial assistance from Bridgette Schafer and Rebecca Riess.

This report is made possible by the generous support of OpenAI.

DIGITAL ENERGY COUNCIL

Submitted via email

The Honorable Brett Guthrie
Chairman
House Committee on Energy and Commerce
Washington, DC 20515

The Honorable Frank Pallone
Ranking Member
House Committee on Energy and Commerce
Washington, DC 20515

April 9, 2025

Dear Chairman Guthrie and Ranking Member Pallone:

The Digital Energy Council (DEC) appreciates the opportunity to submit this Letter for the Record as part of the House Committee on Energy and Commerce's hearing entitled, "Converting Energy into Intelligence: the Future of AI Technology, Human Discovery, and American Global Competitiveness." Highlighting the intersection of artificial intelligence, energy infrastructure, and global competitiveness is a critical opportunity to reinforce the role of energy innovation, particularly digital energy infrastructure, as a cornerstone of the United States' technological and economic leadership.

About the Digital Energy Council

The Digital Energy Council is a non-profit advocacy organization whose members work at the forefront of the energy and technology industries. DEC was founded to shape the future of energy use and inform policymakers about the important cross-section between the energy industry and the digital applications driving a new economy. As society becomes increasingly digital, the energy sector must evolve to keep pace. It is essential for the energy ecosystem to embrace new technologies and adapt to meet growing demand.

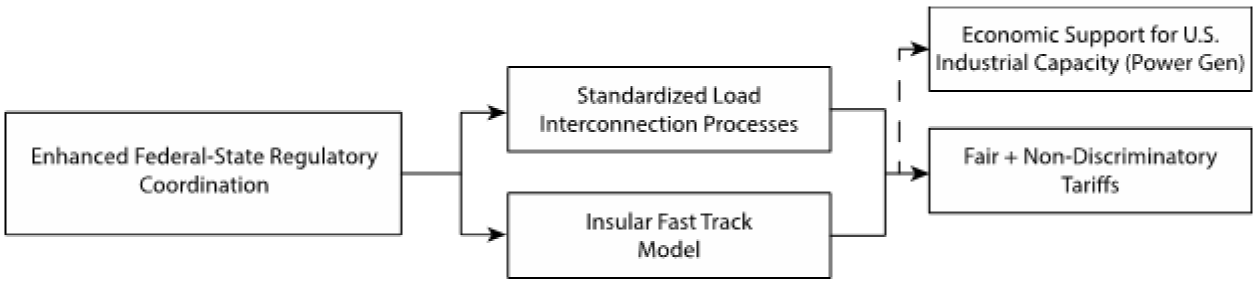
Need for Congressional Action

The U.S. energy system is experiencing a significant growth in demand driven by the 21st century digital economy. The energy sector is exploring innovative methods of leveraging energy resources to meet demand associated with digital technologies. Developments in technology are using approximately 2-3% of the total electricity in the United States, according to NERC's 2024 Long-Term Reliability Assessment found that demand is estimated to increase by 151 gigawatts. in conjunction with buildout of large-scale computing facilities.[1]

1 N. AM. ELEC. RELIABILITY CORP., 2024 Long-Term Reliability Assessment (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20A ssessment_2024.pdf.

In reference to artificial intelligence (AI), bitcoin mining, and high-performance computing (HPC), the concept of "digital energy" represents the synergy between the broader energy sector and the technologies driving the digital economy that require significant computational power. These new technologies can work with our energy systems efficiency, reliability, and can even foster new domestic resource development. To meet the rising demand for energy, it is imperative that Congress acts to support innovative solutions in this growing field.

Policy Recommendations



1. ***Enhance Federal-State Regulatory Coordination*** – Energy infrastructure and markets span multiple states, a patchwork of state regulatory policies can lead to shifting costs and negatively impact retail customers within states, regions, and even nationwide. Enhancing federal-state regulatory coordination can lead to best practices and promote consistent policies that prevent unfair cost burdens and promote efficient project execution.
    a. Identify a single point of interface for all parties to sign off on permits (e.g., similar to the Grid Deployment Office's (GDO) CITAP for transmission). This could allow all generation permits and interconnect requests to be put in one place.
    b. Establish a coordinating body for priority projects with both oversight of the process but also political power to move the various parts of federal and state governments.
    c. Identify criteria for entry into the permit 'fast lane.' These criteria should be technology agnostic, but does not have to be criteria agnostic. For instance, access to the 'fast lane' should be given only to projects that meet a 90/10 test (i.e., the project demonstrates 90% deliverability in 10% peak net load hours) as well as being able to demonstrate commercial viability.

2. ***Develop Best Practices for Standardized Load Interconnection Processes*** – Establish a simplified standard process that can be leveraged to better assess load interconnection requests strictly based on existing grid conditions. For fast-track projects, processes can be done provisionally but are not binding to the utility until other permits are complete (i.e., it happens last, therefore prioritization goes to projects that are real).

3. ***Ensure Fair and Non-Discriminatory Electricity Tariffs*** – Establish equitable tariff structures that are based on actual usage and energy load, rather than directed end use

categories. These tariffs should apply to all firms in a distinct tariff class, driven solely by their energy consumption and not by their sector or size. Additionally, these tariffs should support large-scale, energy-intensive technology development while promoting global competition for data and AI leadership. It is crucial that the tariff structures do not unfairly transfer costs to smaller manufacturers in other sectors or to residential customers, ensuring that all players in the tech ecosystem are treated equitably.

4. ***Economic Support for U.S. Industrial Capacity*** - Congress can help strengthen U.S. industrial capacity by facilitating investment in enabling infrastructure such as pipelines and transmission lines through targeted funding and credit support. It can also reduce deployment constraints by streamlining permitting processes and encouraging coordinated, cross-jurisdictional planning for large-scale projects.

5. ***Federal Land and National Lab Utilization*** - Support greater collaboration between national laboratories and the energy and technology industries. Building on recent proposals, including the Trump Administration's identification of 16 federal sites—many of which include national labs—the DEC calls on Congress to allocate dedicated funding to these laboratories. This funding should support critical efforts in modeling, technology development, and research advancement necessary to drive progress in the digital energy sector.

6. ***Modernize Outdated Regulations and Permitting Processes*** - Policymakers have a vital role in enabling smart, efficient energy infrastructure investment. In most cases, planning for new energy and technology deployment requires 5-7 years to proceed through all regulatory considerations when associated with new co-located power generation. DEC supports clear, forward looking regulatory frameworks that empower private sector innovation in both energy and technology, and streamlines permitting to accelerate deployment of digital energy capabilities.

7. ***Support Economic Development in Rural Areas*** - The development of digital infrastructure will provide jobs in rural areas by driving local economic growth through the establishment of infrastructure and technology hubs. Additionally, energy and technology can spur growth in related sectors, such as construction, maintenance, and service industries, further increasing job prospects. As technology development often relies on low-cost energy sources, rural areas with access to lower electricity rates can attract these investments, contributing to long-term regional development and improved local economies.

8. ***Provide Clear, Uniform Definitions*** - Uniform definitions are essential for the government to effectively regulate new technology and energy coordination because they provide clear, consistent standards that ensure fair application of laws and policies. By establishing uniform definitions, governments can create a level playing field, ensure transparency, and safeguard public interests, while also fostering innovation.

Texas Leads in Grid Innovation

Under existing regulatory structures, Texas represents the best-in-class environment for data, AI, and manufacturing sectors to deploy digital energy infrastructure. This is a result of several unique characteristics:

- The Texas utility sector (ERCOT) operates as its own island, independent of interstate commerce, thereby bypassing the need for federal approval through the Federal Energy Regulatory Commission (FERC).
- Enhanced access to natural gas supply abundance requiring relatively little new infrastructure deployment (i.e., pipeline networks).
- Incentivizes new technology development through programs such as the ERCOT Demand Response Program allowing large electricity consumers to shift power usage during peak demand periods in exchange for financial benefits.
- Texas offers a conducive business environment including regulatory certainty for companies to invest in infrastructure projects in the state.

Conclusion

The Digital Energy Council applauds the Committee's leadership in convening this timely hearing. As AI continues to reshape energy and technology markets, the United States must ensure its energy strategy is resilient, robust, and reliable. DEC looks forward to continued engagement with the Committee to promote policies that harness digital energy to power American innovation. Please feel free to utilize the DEC as a resource for these important and complex issue areas. If you have any questions, we can be reached at info@digitalenergycouncil.org.

Best Regards,

Tom Mapes
Founder and President
Digital Energy Council

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2024 Long-Term Reliability Assessment

December 2024

Table of Contents

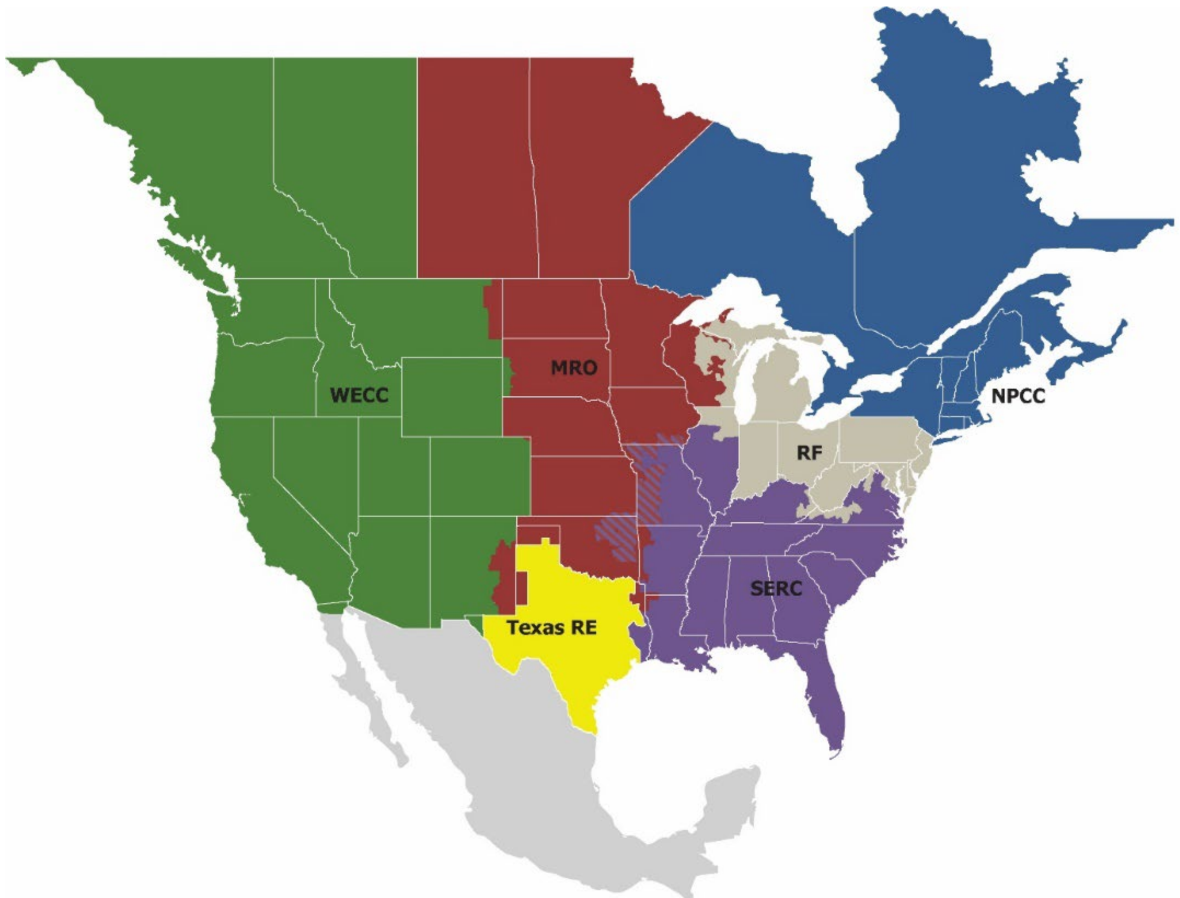
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area basis (see **Regional Assessments Dashboards**) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer-review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer-review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

NERC develops the *Long-Term Reliability Assessment* (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations;[3] this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2024 about known system changes with updates incorporated prior to publication. This *2024 LTRA* assessment period includes projections for 2025–2034; however, some figures and tables examine data and information for the 2024 year. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the **Demand Assumptions and Resource Categories** section of this report. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; it is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policymakers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

---

[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the How NERC Defines BPS Reliability section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

[5] ERO Reliability Assessment Process Document

Assumptions

In this *2024 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2024. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

1. **A reliability assessment of the North American BPS with the following goals:**
    a. Evaluate industry preparations that are in place to meet projections and maintain reliability
    b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
    c. Identify emerging reliability issues
    d. Focus the industry, policymakers, and the general public's attention on BPS reliability issues
    e. Make recommendations based on an independent NERC reliability assessment process
2. **A regional reliability assessment that contains the following:**
    a. A 10-year data dashboard
    b. Summary assessments for each assessment area
    c. A focus on specific issues identified through industry data and emerging issues
    d. A description of regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

In the *2024 LTRA*, NERC finds that most of the North American BPS faces mounting resource adequacy challenges over the next 10 years as surging demand growth continues and thermal generators announce plans for retirement. New solar PV, battery, and hybrid resources continue to flood interconnection queues, but completion rates are lagging behind the need for new generation. Furthermore, the performance of these replacement resources is more variable and weather-dependent than the generators they are replacing. As a result, less overall capacity (dispatchable capacity in particular) is being added to the system than what was projected and needed to meet future demand. **The trends point to critical reliability challenges facing the industry: satisfying escalating energy growth, managing generator retirements, and accelerating resource and transmission development.**

This *2024 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next 10 years; it also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS. The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors. Summaries of the report sections are provided below.

Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions. NERC's evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used both a probabilistic assessment and a reserve margin analysis to assess the risk of future electricity supply shortfalls. Both are forward-looking snapshots of resource adequacy that are tied to industry forecasts of electricity supplies, demand, and transmission development.

Areas categorized as **High Risk** fall below established resource adequacy criteria in the next five years. High-risk areas are likely to experience a shortfall in electricity supplies at the peak of an average summer or winter season. Extreme weather, producing wide-area heat waves or deep-freeze events, poses an even greater threat to reliability. **Elevated-Risk** areas meet resource adequacy criteria, but analysis indicates that extreme weather conditions are likely to cause a shortfall in area reserves. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions. The results of the risk assessment are depicted in **Figure 1**.

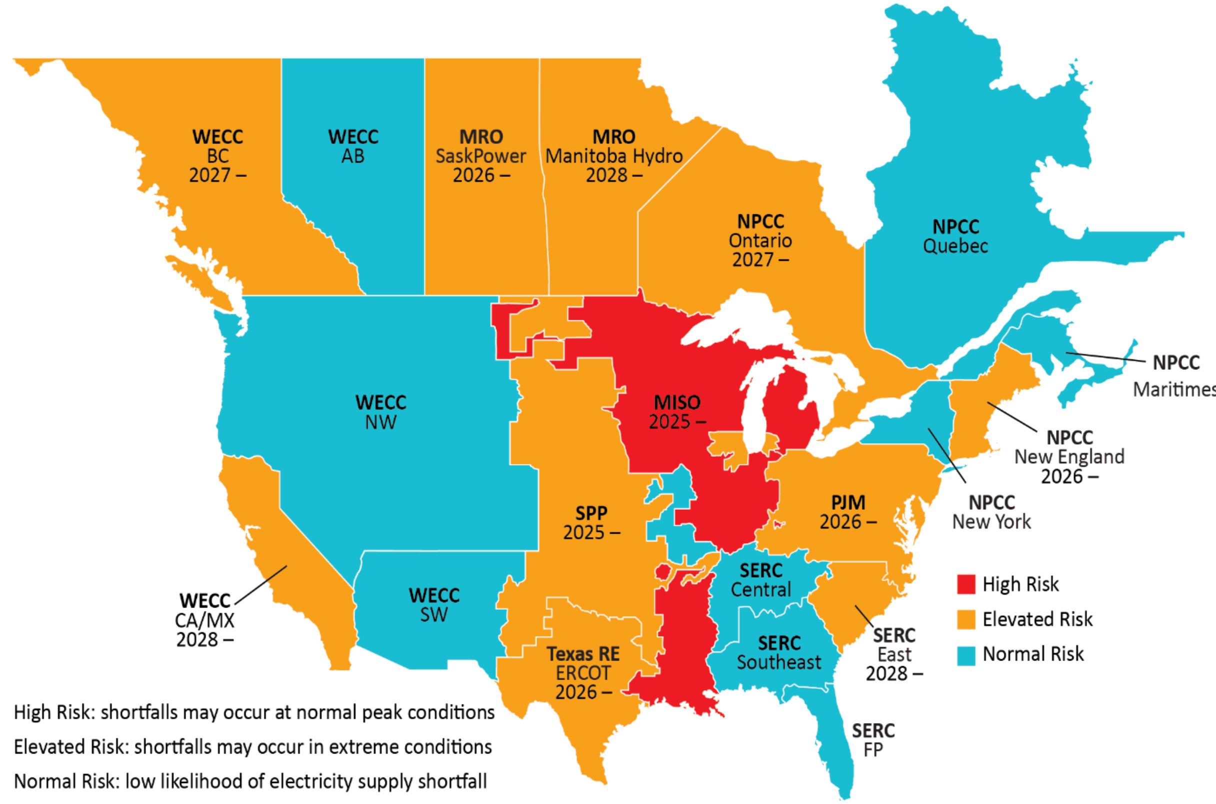


Figure 1: Risk Area Summary 2025–2029

Regional Assessments Dashboards

The **Regional Assessments Dashboards** section contains dashboards and summaries for each of the 20 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic Assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

Table 1: Capacity and Energy Risk Assessment Area Summary			
Area	**Risk Level**	**Years**	**Risk Summary**
MISO	High	2025 -	Resource additions are not keeping up with generator retirements and demand growth. Reserve margins fall below Reference Margin Levels (RML) in winter and summer.
Manitoba	Elevated	2028 -	Potential resource shortfalls in low-hydro conditions, driven by rising demand.
SaskPower	Elevated	2026 -	Risk of insufficient generation during fall and spring when more generators are off-line for maintenance.
Southwest Power Pool (SPP)	Elevated	2025 -	Potential energy shortfalls during peak summer and winter conditions arise from low wind conditions and natural gas fuel risk.
New England	Elevated	2026 -	Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of supply shortfalls in extreme winter conditions.
Ontario	Elevated	2027 -	Reserve margins fall below RMLs as nuclear units undergo refurbishment and some current resource contracts expire. Demand growth is also adding to resource procurement needs.
PJM	Elevated	2026 -	Resource additions are not keeping up with generator retirements and demand growth. Winter seasons replace summer as the higher-risk periods due to generator performance and fuel supply issues.
SERC-East	Elevated	2028 -	Demand growth and planned generator retirements contribute to growing energy risks. Load is at risk in extreme winter conditions that cause demand to soar while supplies are threatened by generator performance, fuel issues, and inability to obtain emergency transfers.
ERCOT	Elevated	2026 -	Surging load growth is driving resource adequacy concerns as the share of dispatchable resources in the mix struggles to keep pace. Extreme winter weather has the potential to cause the most severe load-loss events.
California-Mexico	Elevated	2028 -	Demand growth and planned generator retirements can result in supply shortfalls during wide-area heat events that limit the supply of energy available for import.
British Columbia	Elevated	2027 -	Drought and extreme cold temperatures in winter can result in periods of insufficient operating reserves when neighboring areas are unable to provide excess energy.

Risk from Additional Generator Retirements

Plans for generator retirements continue at similar pace and scale to levels reported in the *2023 LTRA*. Confirmed generator retirements (52 GW by 2029 and 78 GW over the 10-year period) are accounted for in the Capacity and Energy Risk Assessment above. Economic, policy, and regulatory factors spur further fossil-fired generators to retire in the 10-year horizon. Announced retirements, which include many generators that have not begun formal deactivation processes with planning entities, total 115 GW over the 10-year period. The effect of all retirements on the assessment area Planning Reserve Margins (PRM) can be seen in **Figure 2**. On-peak reserve margins fall below RMLs; the levels required by jurisdictional resource adequacy requirements) in the next 10 years in almost every assessment area, signaling an accelerating need for more resources.

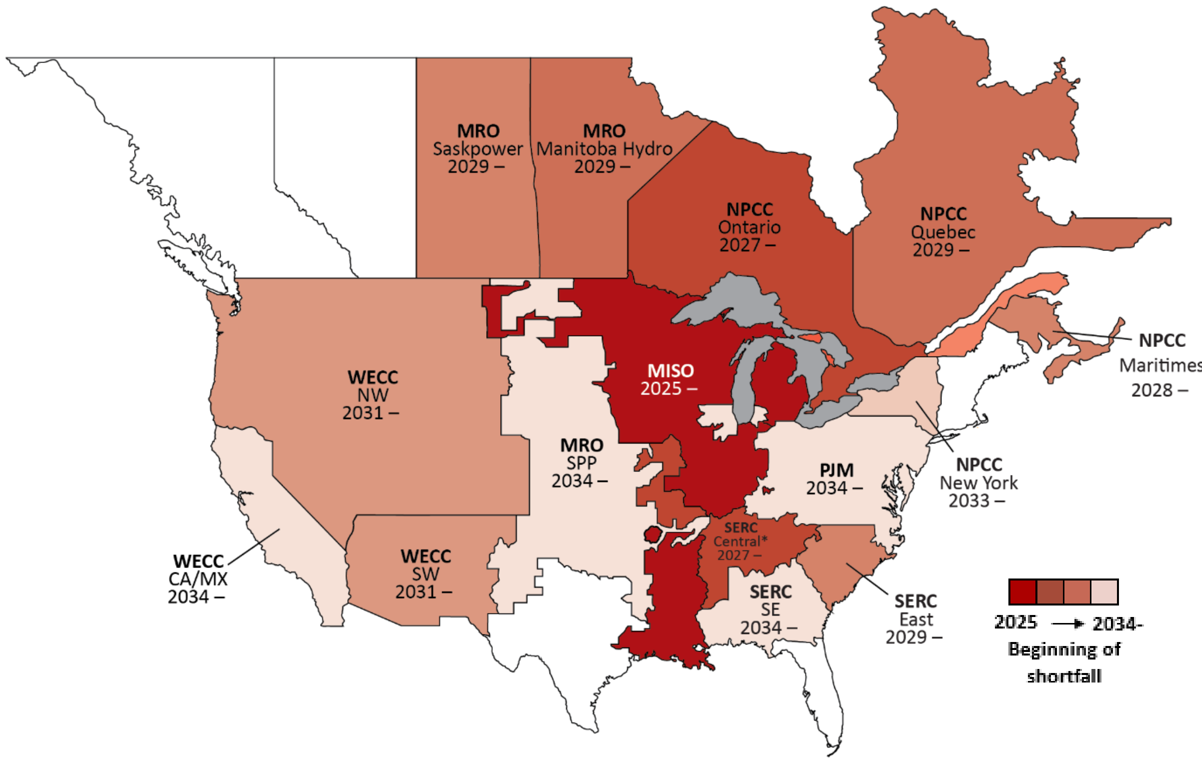


Figure 2: Projected Reserve Margin Shortfall Areas

Changing Resource Mix and Reliability Implications

New resource additions continue at a rapid pace. Solar PV remains the overwhelmingly predominant generation type being added to the BPS followed by battery and hybrid resources, natural-gas-fired generators, and wind turbines. New resource additions fell short of industry's projections from the *2023 LTRA* with the notable exception of batteries, which added more nameplate capacity than was reported in development last year.

As older fossil-fired generators retire and are replaced by more solar PV and wind resources, the resource mix is becoming increasingly variable and weather-dependent. Solar PV, wind, and other variable energy resources (VER) contribute some fraction of their nameplate capacity output to serving demand based on the energy-producing inputs (e.g., solar irradiance, wind speed). The new resources also have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. As generators are deactivated and replaced by new types of resources, ERS must still be maintained for the grid to operate reliably.

Natural-gas-fired generators are a vital BPS resource. They provide ERSs by ramping up and down to balance a more variable resource mix and are a dispatchable electricity supply for winter and times when wind and solar resources are less capable of serving demand. Natural gas pipeline capacity additions over the past seven years are trending downward, and some areas could experience insufficient pipeline capacity for electric generation during peak periods.

Trends and Reliability Implications

Demand and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the **Demand Trends and Implications** and **Transmission Development and Interregional Transfer Capability** sections.

Demand Trends

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb; demand growth is now higher than at any point in the past two decades. Increasing amounts of large commercial and industrial loads are connecting rapidly to the BPS. The size and speed with which data centers (including crypto and AI) can be constructed and connect to the grid presents unique challenges for demand forecasting and planning for system behavior. Additionally, the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America. The aggregated BPS-wide projections for both winter and summer have increased massively over the 10-year period:

- The aggregated assessment area summer peak demand forecast is expected to rise by 15% for the 10-year period: 132 GW this LTRA up from over 80 GW in the *2023 LTRA*.
- The aggregated assessment area winter peak demand forecast is expected to rise over almost 18% for the 10-year period: 149 GW this LTRA up from almost 92 GW in the *2023 LTRA*.

Transmission Trends

For the first time in recent years, transmission projections reported for the LTRA reflect a significant increase in transmission development. This year's cumulative level of 28,275 miles of transmission (>100 kV) in various stages of development for the next 10 years is substantially higher than the *2023 LTRA* 10-year projections (18,675 miles) and is above the average of the past five years of NERC's LTRA reporting on average (18,900 miles of transmission planning projects in each 10-year period published in the last five LTRAs). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning stages of development.

New transmission projects are being driven to support new generation and enhance reliability. Transmission development continues to be affected by siting and permitting challenges. Of the 1,160 projects that are under construction or in planning for the next 10 years, 68 projects totaling 1,230 miles of new transmission are delayed by siting and permitting issues, according to data collected for the LTRA. Questions of cost allocation and recovery can also challenge transmission development when the benefits apply to more than one area, as often occurs with projects that enhance interregional transfer capability.

In NERC's separate Interregional Transfer Capability Study (ITCS), which was performed to meet requirements contained in the Fiscal Responsibility Act of 2023, NERC found that an additional 35 GW of transfer capability across the United States would strengthen energy adequacy under extreme conditions. Increasing transfer capability between neighboring transmission systems has the potential to alleviate energy shortfalls in some areas identified in this LTRA's **Capacity and Energy Risk Assessment**. Conversely, when resource plans are developed that address these same energy shortfalls, such as through resource additions, demand-side management initiatives, or changes to generator retirement plans, the need for increased transfer capability will also change. Planners have options for reducing energy adequacy risks from extreme weather. Selecting the best course of action will depend on weighing these options against various engineering, economic, policy, reliability, and resilience objectives.

The ITCS provides foundational insights that facilitate stakeholder analysis and actions; it is not a transmission plan. In the future, NERC will extend the study beyond the congressional mandate to include transfer capabilities from the United States to Canada and among Canadian provinces.

Emerging Issues

The **Emerging Issues** section discusses developments and trends that have the potential to substantially change future long-term demand and resource projections, resource availability, and reliable operations of the BPS. Topics include data centers and large industrial loads, battery energy storage systems, electric vehicles and load, and energy drought. NERC's RSTC has formed new task forces where needed to address emerging issues.

Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

1. **Integrated Resource Planners, market operators, and regulators: Carefully manage generator deactivations.** Independent System Operator/Regional Transmission Organizations (ISO/RTOs) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulatory and policy-setting organizations must use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be developed and placed in service.
2. **NERC and Regional Entities: Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year's LTRA. To be more effective in using energy criteria and outputs of probabilistic analysis, NERC must specify consistent methods and assumptions for assessment areas to follow in preparing the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC's LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy. Finally, NERC should work with the Regional Entities to perform wide-area energy analysis with modeled interregional transfer capability. Wide-area energy analysis will support the evaluation of extreme weather and regional fuel supply issues on an interconnection level.
3. **Regulators and Policymakers: Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, delays from siting and permitting activities will need to be reduced. These are the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.
4. **Regulators, electric industry, and gas industry member organizations: Implement a framework for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** Various initiatives were launched in the past year to address the reliability needs that arise from the complexity of interconnecting natural gas and electric infrastructure. Voluntary actions taken by the natural gas industry in response to the North American Energy Standards Board (NAESB) Forum report are a positive step toward improving winter readiness. The National Association of Regulatory Utility Commissioners (NARUC) launched its Gas-Electric Alignment for Reliability (GEAR) task force this year and recently created the Natural Gas Readiness Forum. For its part, NERC continues to collaborate extensively with industry and policymakers. NERC has enhanced its Reliability Standards requiring generators to prepare for winter extremes, implement training, and establish communication protocols between generators and grid operators. Current standards projects encompass extreme weather planning and energy assurance requirements. NERC will continue to provide full support to initiatives aimed at achieving a reliable interconnected energy system and urges regulators and policymakers to support needed avenues of coordination between the two sectors.
5. **Regional transmission organizations, independent system operators, and FERC: Continue to ensure essential reliability services are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.[7] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. All recommendations are listed in the Recommendations and ERO Actions Summary section.

[7] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

CATO
POLICY
ANALYSIS

MARCH 11, 2025 NUMBER 991

The Budgetary Cost of the Inflation Reduction Act's Energy Subsidies

IRA Energy Tax Credits Could Cost $4.7 Trillion by 2050

BY TRAVIS FISHER AND JOSHUA LOUCKS

EXECUTIVE SUMMARY

The Inflation Reduction Act (IRA) became law on August 16, 2022. Despite its name, the act was mostly designed to decarbonize the US economy by providing subsidies to producers of clean energy and consumers of low-carbon-emitting preferred products such as electric vehicles.

A contentious point of debate surrounding the passage of the IRA was its budgetary impact—how much liability American taxpayers would have to take on to subsidize clean energy. Various governmental and nongovernmental organizations estimated fiscal costs that turned out to be too low and that they later revised upward.

Using a transparent budget scoring methodology, we estimate that the energy subsidies in the act will cost between $936 billion and $1.97 trillion over the next 10 years, and between $2.04 trillion and $4.67 trillion by 2050. This estimate is substantial because several of the IRA's largest subsidies are uncapped.

When Congress passed the IRA, the Congressional Budget Office (CBO) and the Joint Committee on Taxation (JCT) estimated the energy-related IRA subsidies would cost about $370 billion. An analysis by Goldman Sachs later estimated the IRA's 10-year cost would be $1.2 trillion.

However, the IRA's energy subsidies are multiple times larger than initial estimates, and they expose American taxpayers to potentially unlimited liability. Congress should repeal all the energy subsidies in the IRA. At a minimum, Congress should cap total spending on energy subsidies and require budget experts at the CBO, JCT, and other government organizations to publish transparent and updated estimates of the IRA's long-term costs.


TRAVIS FISHER is the director of energy and environmental policy studies at the Cato Institute. **JOSHUA LOUCKS** is a research associate in energy and tax policy at the Cato Institute.

INTRODUCTION

The Inflation Reduction Act (IRA) became law on August 16, 2022. Despite its name, the act was mostly designed to expedite the decarbonization of the US economy by providing subsidies to producers of low-emission energy and some consumers of low-carbon-emitting products such as electric vehicles. A contentious point of debate surrounding the passage of the IRA was the various estimates of its budgetary impact—how much liability American taxpayers would have to take on to subsidize clean energy. Various governmental and nongovernmental organizations estimated fiscal costs that turned out to be too low and that they later revised upward.

In this paper we aim to explain the energy spending in the IRA and demonstrate that it is highly variable, uncapped, and has been underestimated; provide a transparent and replicable method for scoring the IRA in the upcoming 10-year budget window; estimate a range of total spending (total taxpayer liability) through 2050; highlight the major spending drivers; and advocate for full legislative repeal of the IRA while noting significant reforms that could be made to the IRS guidance and regulations dealing with IRA implementation.

Table 1 summarizes the upper- and lower-bound estimates of energy spending in the IRA, both for the coming 10-year budget window and for a longer budget window stretching to 2050. It also shows the effect of applying a 3 percent discount rate to the spending in the 2050 budget window, which is to reduce the net present value of the stream of IRA spending by approximately 30 percent.

History of the Inflation Reduction Act

The most salient goal of the IRA was not to reduce inflation—it was to accelerate the decarbonization of the US economy. In July 2024, President Joe Biden wrote that his administration had passed "the most important climate legislation in the history of the world."[1] Biden is correct if we judge the significance of legislation by the amount of government spending it enables—there is not a single piece of legislation or other government action that commits more public spending to address climate change than the IRA.[2]

Biden signed the IRA into law on August 16, 2022, following party-line votes in the House and the Senate, to pass the bill through the budget reconciliation process.[3] Advancing as a budget reconciliation measure meant the IRA could pass on a simple majority in the Senate instead of requiring a filibuster-proof majority of 60 Senate votes.[4] By the same token, the IRA can be repealed as part of a budget reconciliation package.

The final version of the IRA was the culmination of a long process of shaping the climate portion of Biden's Build Back Better agenda.[5] An earlier iteration of climate-related spending was approved by the House Energy and Commerce Committee in 2021 as the Clean Electricity Performance Program—scored at approximately $150 billion of the $3.5 trillion Build Back Better package—but this early proposal failed to gain political traction.[6] The IRA ultimately moved forward with the energy subsidies analyzed in this paper and some provisions unrelated to climate, such as price caps on medication.[7]

Table 2 summarizes the various energy-related subsidies in the IRA and shows the expiration dates for each, as well as the locations of each provision in the IRA statute and the IRS code.

TOTAL IRA SPENDING IS DIFFICULT TO ESTIMATE

Other estimates of IRA spending range from about $350 billion to more than $1 trillion. When Congress passed the IRA, the Congressional Budget Office (CBO) and the Joint Committee on Taxation (JCT) estimated that its energy-related subsidy provisions would cost between $369 billion and $383 billion over the 10-year budget window. In contrast, several third-party estimates suggested that costs could exceed three times those projected by the CBO and the JCT.[8] The wide range in estimates is a result of the open-ended nature of many of the IRA's energy subsidies, which are highly sensitive to factors such as industry growth, market adoption, and technological advancements.

Each provision in Table 2 represents a different category of spending that contributes to the ultimate cost of the IRA, and the forecast range of annual spending in each category is wide. Furthermore, the length of the budget window has a significant effect on the analysis. Many of the IRA's subsidy provisions expire in 2032, such as the tax credits for electric vehicles (EVs) and existing nuclear power plants. However,

Table 1

Cato's estimate of energy spending in the Inflation Reduction Act

Scoring window	2025–2034	2025–2050
Upper bound	$1.97 trillion	$4.67 trillion
Discounting 2050 total at 3%		$3.26 trillion
Lower bound	$936 billion	$2.04 trillion
Discounting 2050 total at 3%		$1.47 trillion

Sources: Authors' calculations; "Annual Energy Outlook 2023," US Energy Information Administration, March 2023; and Pieter Gagnon et al., "2023 Standard Scenarios Report: A US Electricity Sector Outlook," National Renewable Energy Laboratory, revised January 2024.
Note: Please contact the authors to request a copy of the underlying datasets we used and to see our calculations.

Table 2

Energy subsidy provisions in the Inflation Reduction Act: expiration dates and key details

Provisions	Expiration date	Notes	IRA section(s)	Internal Revenue Code section(s)
Clean vehicle credits	2032		Sec. 13401, 13402, 13403, 13404	Sec. 25E, 30C, 30D, 45W
Residential clean energy credit	2034	Storage portion begins phaseout in 2032 and ends in 2035	Sec. 13302	Sec. 25D
Energy efficient home credit	2032		Sec. 13304	Sec. 45L
Clean hydrogen production credit	2042	Construction must begin by 2032, credit extends for the first 10 years of life	Sec. 13204	Sec. 45V
Credit for carbon sequestration	2044	Facility must be developed by 2032, credit extends for 12 years beyond the development date	Sec. 13104	Sec. 45Q
Production tax credit for electricity from renewables	2024	Rolls into the PTC under section 13701 beginning in 2025	Sec. 13101	Sec. 45
Clean fuel production credit	2028		Sec. 13704	Sec. 45Z
Nuclear production credit	2032		Sec. 13105	Sec. 45U, 45J
Clean electricity production tax credit	Contingent expiration date	Expires when GHG emissions for electricity are below 25% of 2022 levels	Sec. 13701	Sec. 45Y
Clean electricity investment tax credit	Contingent expiration date	Expires when GHG emissions for electricity are below 25% of 2022 levels	Sec. 13702	Sec. 48E
Advanced energy project credit	Expires upon fund exhaustion	Expires once the $10 billion in allocated funds are exhausted	Sec. 13501	Sec. 48C
Advanced manufacturing production credit	No full expiration	Phaseout begins in 2030, fully phased out after 2032 for most provisions; no phaseout for applicable critical materials (as defined under Sec. 45X(b)(3)(C))	Sec. 13502	Sec. 45X

Source: 117th Congress, Inflation Reduction Act of 2022, Pub. L. No. 117-169, 136 Stat. 1818, August 16, 2022.

some of the IRA's largest subsidies phase down only when the level of greenhouse gas (GHG) emissions from the electricity sector falls to 25 percent of the 2022 baseline.[9]

The electricity sector is highly unlikely to reduce the GHG emissions by 75 percent from 2022 levels in the next 10 years, especially if electricity demand continues to grow.[10] Further, the IRA promotes electrification—as with EVs—which will contribute to increased electricity demand, thus making the GHG target more difficult to reach. Figure 1 illustrates GHG projections from the Energy Information Administration (EIA), which show that electricity sector emissions will remain far above the IRA's target of 25 percent of the 2022 level through 2050, even in the scenario that assumes a "high uptake" of IRA subsidies.[11]

Major Spending Drivers

Some of the costliest provisions of the IRA are the production tax credit (PTC) and the investment tax credit (ITC) for clean electricity production under IRS code sections 45Y and 48E, respectively, and the advanced manufacturing tax credit under IRS code section 45X. In the case of the 45Y production tax credit, the owner of a power plant that qualifies for clean electricity credits will receive an inflation-adjusted payment per unit of clean electricity produced. In 2023, the going rate for the PTC was $27.50 per megawatt-hour. The section 48E investment tax credit reimburses a percentage—typically 30 percent—of the up-front investment cost of a power plant that produces clean electricity or an electricity storage facility, such as a battery or pumped storage hydroelectric facility. Starting in 2025, a clean electricity production facility will have the option of choosing either the section 45Y production tax credit or the section 48E investment tax credit, but not both. The section 45Y and 48E credits in the IRA will likely cost taxpayers between $70 billion and $180 billion per year in the years just before the GHG target is met.[12]

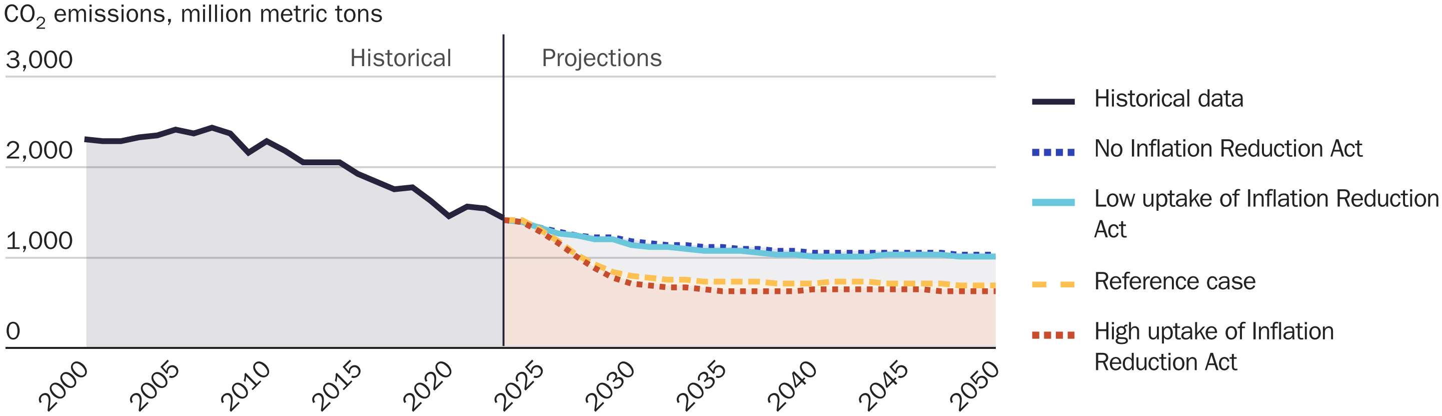
The section 45X tax credit for advanced manufacturing includes an uncapped production tax credit for critical minerals. Under section 45X(c)(6) of the IRS code (section 13502 of the IRA), the federal government will indefinitely subsidize 50 different "critical minerals." This includes high-volume production minerals such as aluminum, lithium, nickel, and cobalt. These subsidies, particularly in the context of rising demand for lithium-ion batteries used for EVs and energy storage, risk creating a compounding effect, where multiple subsidies stack across the supply chain. For example, in a "solar plus storage" context, taxpayers not only subsidize the solar energy production through the PTC, but also the battery through the ITC and the minerals that go into that battery via section 45X(c)(6). Recent guidance on section 48E added another layer of taxpayer liability, as some transmission upgrades for new sources will also be subsidized by the ITC.

Given recent trends—including growing demand for electricity and the looming Trump administration reversal of power plant regulations issued by the Environmental

Figure 1

Electricity sector emissions

CO_2 emissions, million metric tons



Sources: Authors' calculations; "Annual Energy Outlook 2023: Reference Case Projection Tables, Table 18," US Energy Information Administration, March 2023; and "US Energy-Related Carbon Dioxide Emissions, 2023," US Energy Information Administration, April 2024.
Note: Please contact the authors to request a copy of the underlying datasets we used and to see our calculations.

Protection Agency (EPA)—the decarbonization of the grid is likely to slow, or perhaps stall, in terms of total emissions.[13] As one significant data point, the most recent capacity auction for electricity generation resources in the PJM Interconnection, which is the wholesale electricity market covering 13 states in the mid-Atlantic region and the District of Columbia, retained every GHG-emitting power plant that offered capacity.[14] In other regions with faster-growing deployment of renewable resources, such as Texas, decarbonization of the electricity sector has been modest, in part because reductions in the GHG intensity of electricity generation are being offset by increased electricity use overall.[15]

If the growth in nationwide electricity consumption continues, many of the existing GHG-emitting power plants will be needed for reliability—and this is true independent of their profitability. If supply shortfalls are imminent, grid operators will not allow fossil-fueled power plants (mostly coal and natural gas) to close in the near term.[16] Finally, a reversal of the EPA's power plant GHG rule would allow for a variety of natural gas–fired power plants to be built to meet rising electricity demand, further increasing GHG emissions and lengthening the term of subsidies as currently designed in the IRA.[17]

Initial Estimates of the IRA's 10-Year Budget Cost

The one-page summary of the budget impacts of the IRA circulated by Senate Democrats in July 2022 said the Energy Security and Climate Change section of the IRA would cost $369 billion, but it did not itemize the wide-ranging set of provisions.[18] In August 2022, the CBO and the JCT released an itemized estimate that revised the 10-year cost of the IRA's energy-related provisions to approximately $383 billion, due to minor adjustments.[19] These estimates are challenging to deconstruct and replicate because the agencies do not publish replication codes or detailed methodologies. However, third-party estimates from the same period align with the initial CBO and JCT estimates. Researchers using the Penn Wharton Budget Model found that the climate and energy provisions of the IRA would cost $384 billion in August 2022.[20] Also, that same month, the nonpartisan Tax Foundation estimated there to be $352 billion in expanded tax credits in the IRA.[21]

Updated Estimates of the IRA's 10-Year Budget Cost

Although the various initial estimates of IRA spending all clustered around the original score of roughly $370 billion, the CBO and others have since updated their estimates multiple times. As summarized in a February 2024 article by the Tax Foundation, the CBO and the JCT found that "the IRA credits appear to cost approximately $786 billion over the new budget window (2024–2033)."[22] The updated amount is more than double the original CBO and JCT estimate.

Estimates by private firms, think tanks, and researchers are even higher. The updated Penn Wharton Budget Model estimated the IRA's climate and energy provisions will cost just over $1 trillion by 2032.[23] The Brookings Institution found that the 10-year cost could be roughly $800 billion—again, more than twice the CBO's original estimate.[24] A widely circulated report by Goldman Sachs estimated the 10-year cost would be $1.2 trillion, more than triple the CBO's original estimate and 50 percent larger than the CBO's revision.[25] Figure 2 summarizes the findings of these groups as well as Cato's upper- and lower-bound estimates for the upcoming 10-year budget window.

There have been several regulatory changes since the IRA became law that might contribute to the discrepancies in estimates over time. On March 20, 2024, the EPA finalized tighter tailpipe emissions standards that were projected to increase EV sales by raising the relative price of cars with internal combustion engines, which would boost consumer use of the IRA's clean vehicle credit. Those regulations could have contributed to the increase in the cost of the clean vehicle provision from the CBO/JCT's estimate of $14 billion in 2022 to $73 billion in February 2024.[26] The future of the EPA regulations is uncertain, and so is the future of market demand for EVs without the regulations or credits. Figure 2 shows much lower spending on the EV tax credit in the Cato estimates than the Penn Wharton and Goldman Sachs estimates, partly because we expect slower growth in the US EV market due to factors such as consumer demand and other market constraints.

The JCT estimated that changes to regulations—including updated guidance by the IRS—are likely to double initial cost projections for some credits. Goldman Sachs determined that most of the disparities between initial and later cost projections are "driven by higher estimates for all categories, especially our significantly higher estimates for advanced manufacturing tax credits (45X) and EV tax credits."[27] Overall, the 10-year spending estimates have shifted from the initial range of less than $400 billion to a new range of $1 trillion or more.

Early Data from Tax Returns

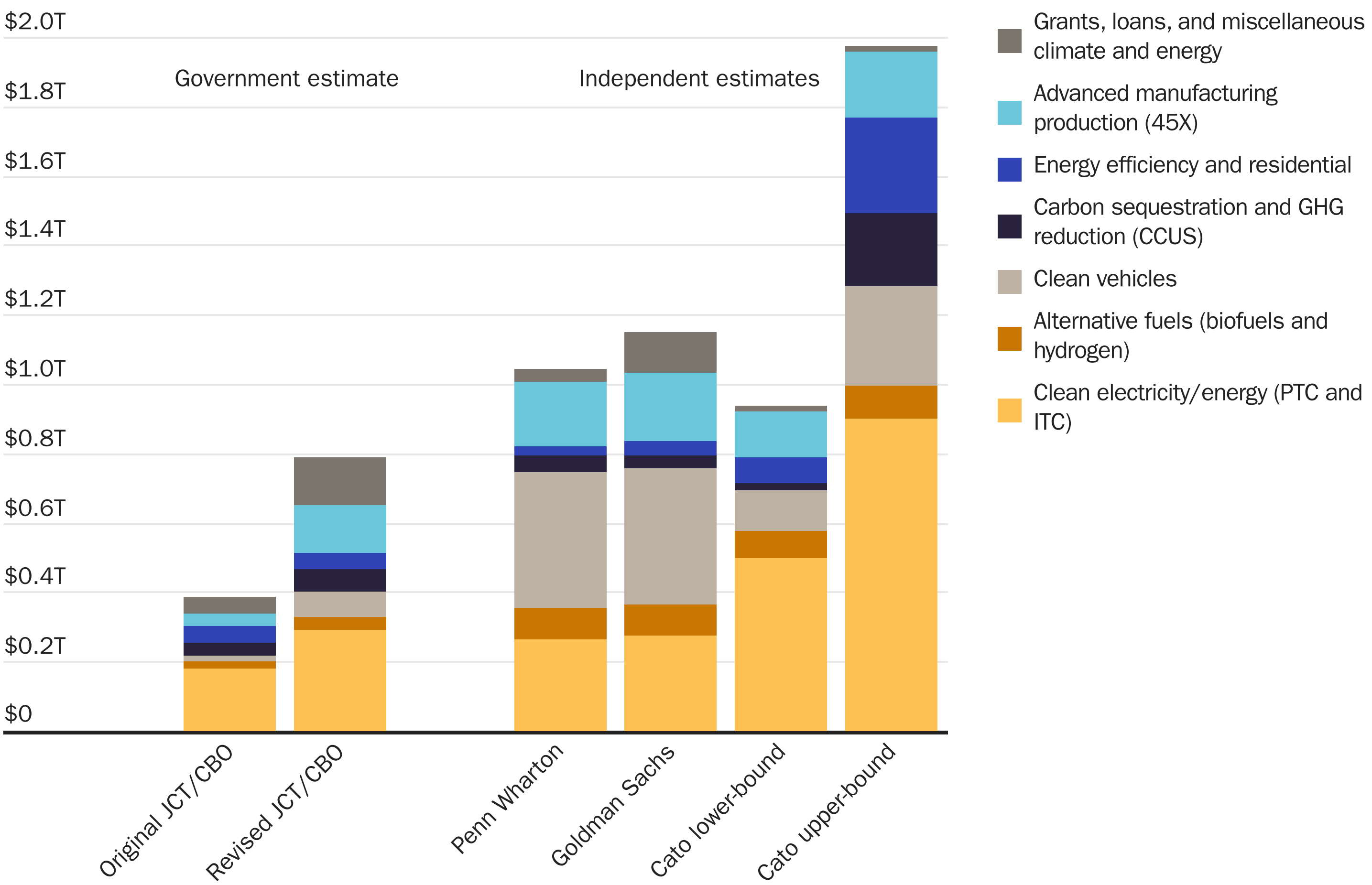
Although IRA spending projections are inherently uncertain, new information from the IRS shows that the actual subsidies included in tax filings have surpassed initial projections. For example, the Treasury Department recently highlighted the rapid uptake of the residential clean energy credit and the energy-efficient home-improvement credit. These two credits cost $8.4 billion in 2023, but initial estimates were a fraction of that.[28]

The residential clean energy credit was estimated to cost $459 million in 2023, with a total cost of $22 billion by 2031.[29] The IRS data show an actual cost to taxpayers of $6.3 billion in 2023, roughly $4 billion of which is attributable to the IRA (as the original credit would have still been in effect until the end of 2023).[30] At this pace, the total cost would exceed $200 billion by 2032.

Figure 2

Comparing third-party estimates of the IRA's fiscal costs to the government's

10-year cost estimates of the IRA's energy and climate-related provisions



Source: Authors' calculations; "Annual Energy Outlook 2023," US Energy Information Administration, March 2023; and Pieter Gagnon et al., "2023 Standard Scenarios Report: A US Electricity Sector Outlook," National Renewable Energy Laboratory, revised January 2024; and "Estimated Budget Effects of the Revenue Provisions of Title I—Committee on Finance of an Amendment in the Nature of a Substitute H.R. 5376," Joint Committee on Taxation, August 9, 2022; and "The Budget and Economic Outlook: 2024–2034," Congressional Budget Office, February 2024; Michele Della Vigna et al., "Carbonomics: The Third American Energy Revolution," Goldman Sachs, March 22, 2023; and Alex Arnon et al., "Senate Passed Inflation Reduction Act: Estimates of Budgetary and Macroeconomic Effects," University of Pennsylvania Wharton Budget Model, August 12, 2022.

Note: Please contact the authors to request a copy of the underlying datasets we used and to see our calculations. PTC = Production Tax Credit; 45X = Internal Revenue Code section that establishes the Advanced Manufacturing Production Credit; ITC = Investment Tax Credit; and CCUS = carbon capture, utilization, and storage.

Actual costs for the energy-efficient home-improvement credit in 2023 were $2.1 billion.[31] This is nearly eight times the original estimate of $273 million for 2023 and exceeds the initially estimated 10-year total of $2 billion.[32] The sharp growth of these two credits shows how initial, and even revised, estimates have been off by billions of dollars, not only collectively but for many of the individual provisions within the IRA.

Estimates of the IRA's Cost Beyond the 10-Year Budget Window

Few modelers have attempted to estimate what the IRA might cost beyond a 10-year window. One such estimate comes from Wood Mackenzie, an energy transition analytics company. Two Wood Mackenzie analysts estimated that the clean electricity portions of the IRA—the PTC and the ITC for clean electricity generation and storage—will cost nearly $3 trillion by 2060.[33] Wood Mackenzie has since identified issues, namely interconnection delays and slow expansion of transmission capacity, that could push the phasedown year for the PTC and the ITC even later because they would delay hitting the 75 percent reduction goal.[34]

HOW WE APPROACH OUR COST ESTIMATES

We create a simple model to estimate a range of spending on the energy subsidies in the IRA. Using projections published by the EIA and the National Renewable Energy Laboratory (NREL), we take levels of deployment for each subsidized technology and estimate the cumulative amounts of the various tax credits in the IRA. This methodology is then applied to all subsidized technologies and investments (electricity generation resources, energy storage, EVs, etc.).

Because there are many moving parts in the IRA framework, we make educated guesses about the type of subsidy a given project developer is likely to select, as well as the magnitude of the subsidy. For example, developers of offshore wind facilities may select the ITC rather than the PTC, so we estimate the offshore wind subsidies in the IRA by multiplying the amount of offshore wind investment by the subsidy level. The range established in the statute goes from 6 percent to at least 50 percent of the cost of the project. We assume a 30 percent ITC. Our estimated offshore wind subsidy for each year, then, based on EIA and NREL projections, is 30 percent of the estimated investment in offshore wind facilities.

We repeat this estimate for each year out to 2050, using projected deployment levels from both the EIA's Annual Energy Outlook and NREL's modeling of state goals for offshore wind. In this case, NREL's projection is significantly higher than the EIA's, so the subsidy estimate that relies on the NREL projection is much higher than the EIA-based estimate. In most cases, the EIA's estimate for subsidy-eligible technologies is lower than NREL's estimate, and the difference in deployment levels between the EIA and NREL provides the lower and upper bound, respectively, for the annual subsidy estimates.

What this paper does not do. We do not offer a mid-point estimate for the total cost of the IRA, either over the 10-year budget window or out to 2050, because there are too many uncertainties involved; our estimates would be based on arbitrary assumptions, and we want to avoid the false appearance of precision. Further, although IRA spending will likely continue beyond 2050, we do not make any spending projections beyond 2050 because the number of variables—including changes to energy technology or broader economic conditions—would push our analysis further toward the realm of pure guesswork. Finally, we do not use capacity expansion models; contributions from these models would be unlikely to contradict our findings.[35] Our goal is to present an IRA spending estimate that is generally accessible, transparent, and replicable using basic spreadsheet software.[36]

Full versus partial credits. Estimates of the IRA's fiscal impact hinge, in part, on whether the full credits are attainable, which depends on variables such as supply-chain decisions made by private companies. For example, some of the ITCs range from 6 percent of the total investment to 50 percent or more, depending on factors such as labor requirements and domestic sourcing of materials. As noted before, to simplify our estimates, we model all ITCs at 30 percent, which is consistent with long-standing levels of the solar ITC.[37] As another example, the tax credit for purchasing an EV depends on production decisions made by automakers and the income level of the household purchasing the EV.[38] In our lower- and upper-bound estimates, we model partial and full EV credits, respectively.

Election of the ITC or the PTC. Developers of new or expanded low-GHG electricity generation resources can choose between an up-front ITC of typically 30 percent or a 10-year stream of PTC payments (the 2023 value of the PTC was $27.50 per megawatt-hour of electricity generation).[39] To model the choice between the ITC and the PTC in our estimates, we assumed that developers of offshore wind and new nuclear resources will elect the ITC, and other energy-generation resources will choose the PTC. Although that assumption may not always be true in all regions or for all years, we believe it will yield accurate results. In addition, the ITC/PTC distinction may not significantly alter the total cost of the IRA by 2050. However, it does change the timing of subsidy payments because spending will occur earlier if more developers choose the ITC and later if more developers choose the PTC and, hence, could impact the discounted values of IRA spending. Notably, for some technologies such as energy storage, which includes everything from batteries to pumped hydroelectric generation resources, the ITC is the only category of IRA subsidy available.

IRS guidance. Many of the cost estimates depend on ongoing changes and clarifications to the implementation guidelines issued by the IRS. For example, owners of some existing low-GHG electricity generators can take advantage of the IRS's so-called 80/20 rule by "repowering," meaning retrofitting facilities that are already in service.[40] In the context of energy tax credits, this rule states that the IRS will treat a retrofitted electricity generation or storage unit as if it were new, and thus it would be eligible for tax credits for new resources if the value of the new components is at least 80 percent of the total market value of the refurbished facility.

We assume that a gradually increasing portion of existing hydroelectric facilities, starting at zero in 2024 and increasing to 25 percent of all hydroelectric generation units by 2050 in our upper-bound estimates, will take advantage of the 80/20 rule.[41] We also assume in our upper-bound estimates that all owners of wind and solar resources will repower and requalify for the PTC when they are eligible to do so.[42] In contrast, our lower-bound estimates assume that no repowering of wind and solar resources takes place.

Data sources and sensitivity analysis. We rely on data from forecasts published by government sources, namely the EIA and NREL. Our assumptions and analysis are informed, in part, by previous work by private and academic researchers, such as Wood Mackenzie, Goldman Sachs, and Princeton University's REPEAT Project.[43] We note that the forecasts we rely on are inherently uncertain and produce large differences in spending estimates.

A major difference between our lower-bound estimate of IRA spending by 2050 and our upper-bound estimate is driven by the difference between the EIA's relatively lower projection of solar generation and NREL's relatively higher projection. Similarly, deployment levels of new or repowered nuclear energy represent about a $600 billion difference between lower- and upper-bound estimates, or zero new deployment versus 200 gigawatts (GW) by 2050, respectively.

The 200 GW upper bound for new nuclear deployment comes from the Biden administration's stated goals and the authors' judgments about possible deployment levels for new nuclear under a high-load growth scenario. For our upper-bound estimates of tax credits for offshore wind and EVs, we also go beyond government projections and substitute relevant policy goals, such as states' offshore wind mandates and the previous administration's goal of EVs being 50 percent of new vehicles sold by 2032.

Figures 3 and 4 show the share of total IRA spending by subsidy category in our lower-bound and upper-bound scenarios, respectively. Note the large difference in ITC payments, which reflects the much higher deployment levels of new nuclear and offshore wind resources in our upper-bound estimate.

In each estimate, our goal is to establish a sound framework for analyzing IRA spending—within the 10-year budget window as well as through 2050—and to advance a transparent and accurate framework for others to build on.[44]

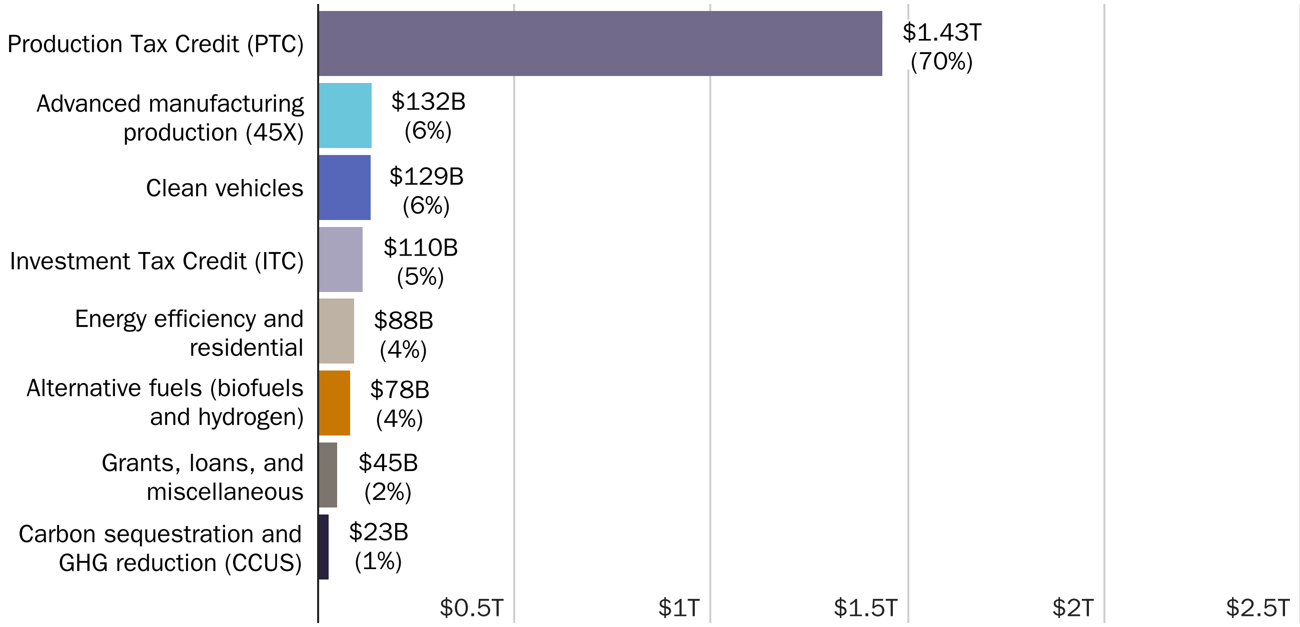
Expiration dates for IRA subsidies. A difficult element to predict is the end date for the energy subsidy provisions that expire only when the electricity sector meets certain GHG targets. To repeat, the PTCs and the ITCs phase down only when the level of GHG emissions from the electricity sector falls to 25 percent of the 2022 level. The required reduction will likely not occur by 2050 because there will be significant growth in electricity demand, making a target based on a GHG level (rather than a GHG intensity) more difficult to reach. This is consistent with NREL modeling.[45]

Although the phasedown year is not easy to forecast, a shorter subsidy window is unlikely to materially change the cost of the IRA between now and 2050 because hitting the

Figure 3

Spending breakdown in Cato's 2050 lower-bound estimate

Lower-bound cost estimate of energy and climate-related provisions



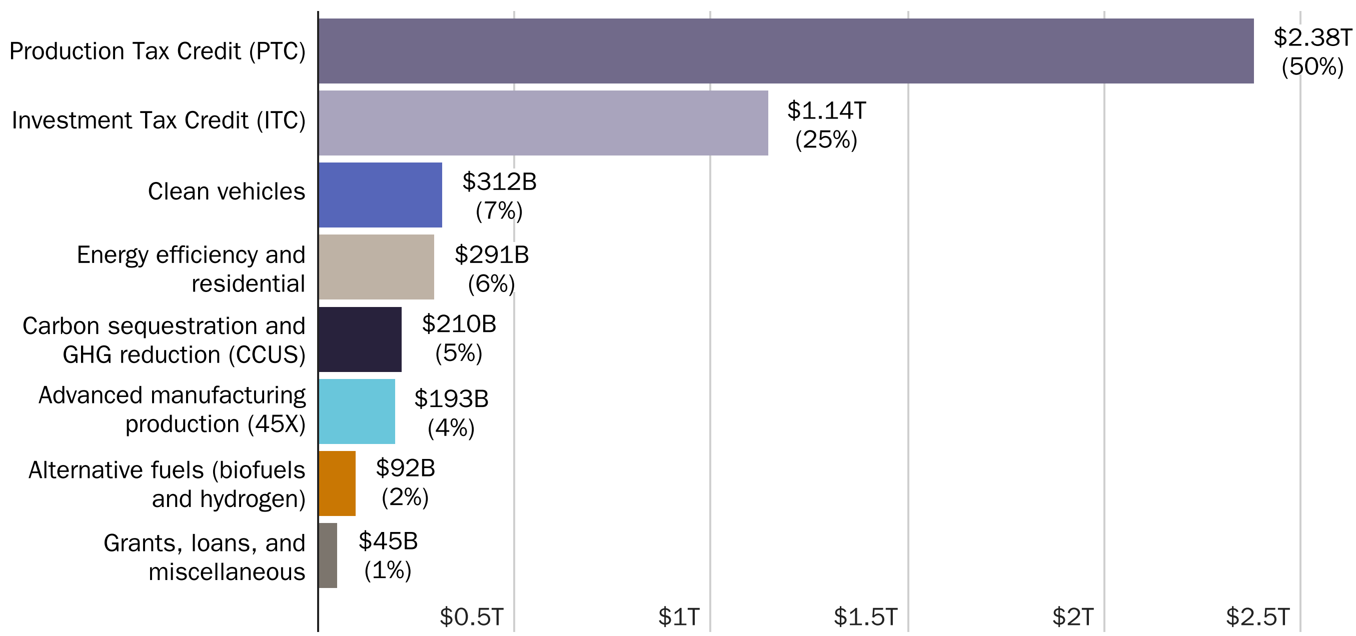
Sources: Authors' calculations; "Annual Energy Outlook 2023," US Energy Information Administration, March 2023; and Pieter Gagnon et al., "2023 Standard Scenarios Report: A US Electricity Sector Outlook," National Renewable Energy Laboratory, revised January 2024.

Notes: Please contact the authors to request a copy of the underlying datasets we used and to see our calculations. PTC = Production Tax Credit; 45X = Internal Revenue Code section that establishes the Advanced Manufacturing Production Credit; ITC = Investment Tax Credit; and CCUS = carbon capture, utilization, and storage.

Figure 4

Spending breakdown in Cato's 2050 upper-bound estimate

Upper-bound cost estimate of energy and climate-related provisions



Sources: Authors' calculations; "Annual Energy Outlook 2023," US Energy Information Administration, March 2023; and Pieter Gagnon et al., "2023 Standard Scenarios Report: A US Electricity Sector Outlook," National Renewable Energy Laboratory, revised January 2024.

Notes: Please contact the authors to request a copy of the underlying datasets we used and to see our calculations. PTC = Production Tax Credit; 45X = Internal Revenue Code section that establishes the Advanced Manufacturing Production Credit; ITC = Investment Tax Credit; and CCUS = carbon capture, utilization, and storage.

GHG target implies aggressive deployment of subsidized resources.[46] In other words, IRA subsidies will be significant even if the GHG targets are achieved well before 2050.

Methodology Specific to the 10-Year Budget Window Estimates

Among the provisions that expire in 2032, we provide our own estimate for some of the tax credits, including the EV credit and the residential clean energy credit. For other provisions, we rely on the CBO, JCT, and other estimates for the contribution of those provisions to total spending. For example, we rely exclusively on external estimates for the total 10-year cost of subsidies for hydrogen production, biofuels, carbon capture, and the manufacturing tax credit. Figure 5 illustrates our upper-bound 10-year estimate broken down by subsidy type.

Methodology Specific to Estimating Beyond the 10-Year Budget Window

Our estimates of the long-term cost of the PTC and the ITC follow the methodology of projecting the amount of subsidized activity, such as eligible clean energy production for the PTC and the eligible clean energy investment for the ITC, and then applying an estimated subsidy. We assume developers of all new onshore wind, solar, geothermal, and hydroelectricity production will claim the standard value of the PTC, which was $27.50 per megawatt-hour in 2023. If new projects elect the ITC rather than the PTC, that will shift projected spending to earlier years because ITC subsidies are paid up front, whereas PTC payments are spread over 10 years but may not substantially change total costs.

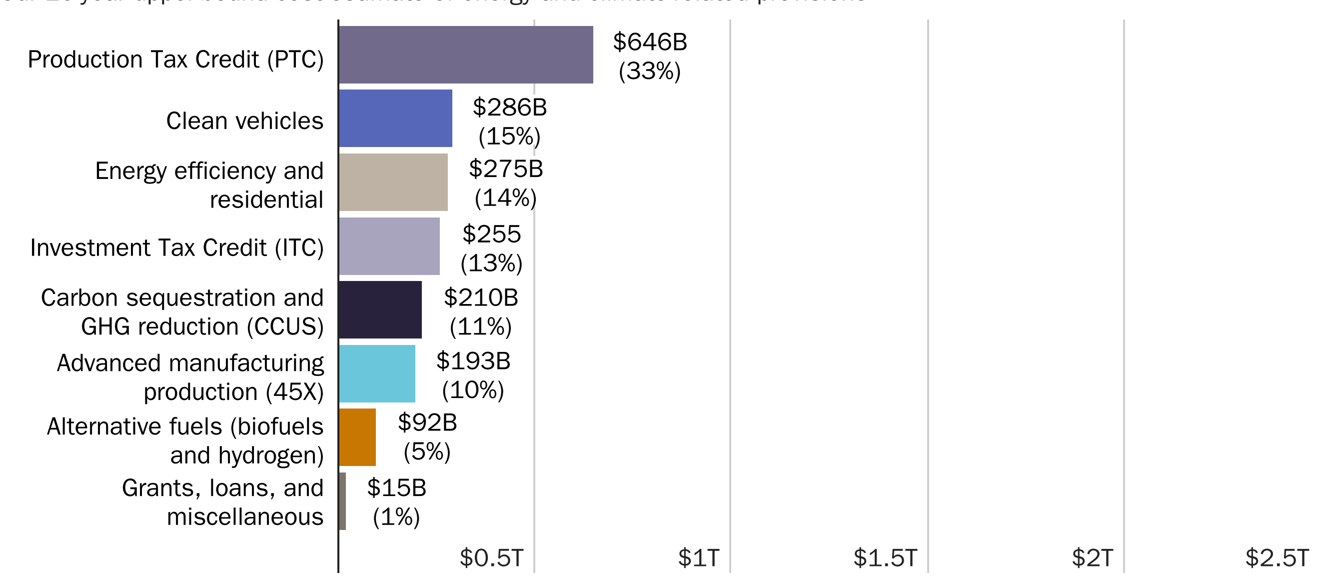
Figure 6 breaks down IRA spending by year and shows the contribution of each type of subsidy. Note that the total spending rises relatively steadily for every year from 2033 through the end of the projection. By 2050, the annual cost of the IRA's energy subsidies reaches $180 billion, which is nearly half the original CBO/JCT score of $369 billion.

We assume developers of all new offshore wind and new nuclear facilities will choose to receive the ITC. Projected levels of investment in offshore wind in each year through 2050 vary significantly—the EIA's Annual Energy Outlook shows little investment (23 GW), whereas NREL modeling of state policies mandating offshore shows high investment (112 GW).[47] To convert installed gigawatts to investment spending, we use the EIA's base overnight construction cost of offshore wind (with no adder applied) of $5,338 per

Figure 5

10-year cost estimate approaching $2 trillion

Our 10-year upper-bound cost estimate of energy and climate-related provisions



Sources: Authors' calculations; "Annual Energy Outlook 2023," US Energy Information Administration, March 2023; and Pieter Gagnon et al., "2023 Standard Scenarios Report: A US Electricity Sector Outlook," National Renewable Energy Laboratory, revised January 2024.

Notes: Please contact the authors to request a copy of the underlying datasets we used and to see our calculations. PTC = Production Tax Credit; 45X = Internal Revenue Code section that establishes the Advanced Manufacturing Production Credit; ITC = Investment Tax Credit; and CCUS = carbon capture, utilization, and storage.

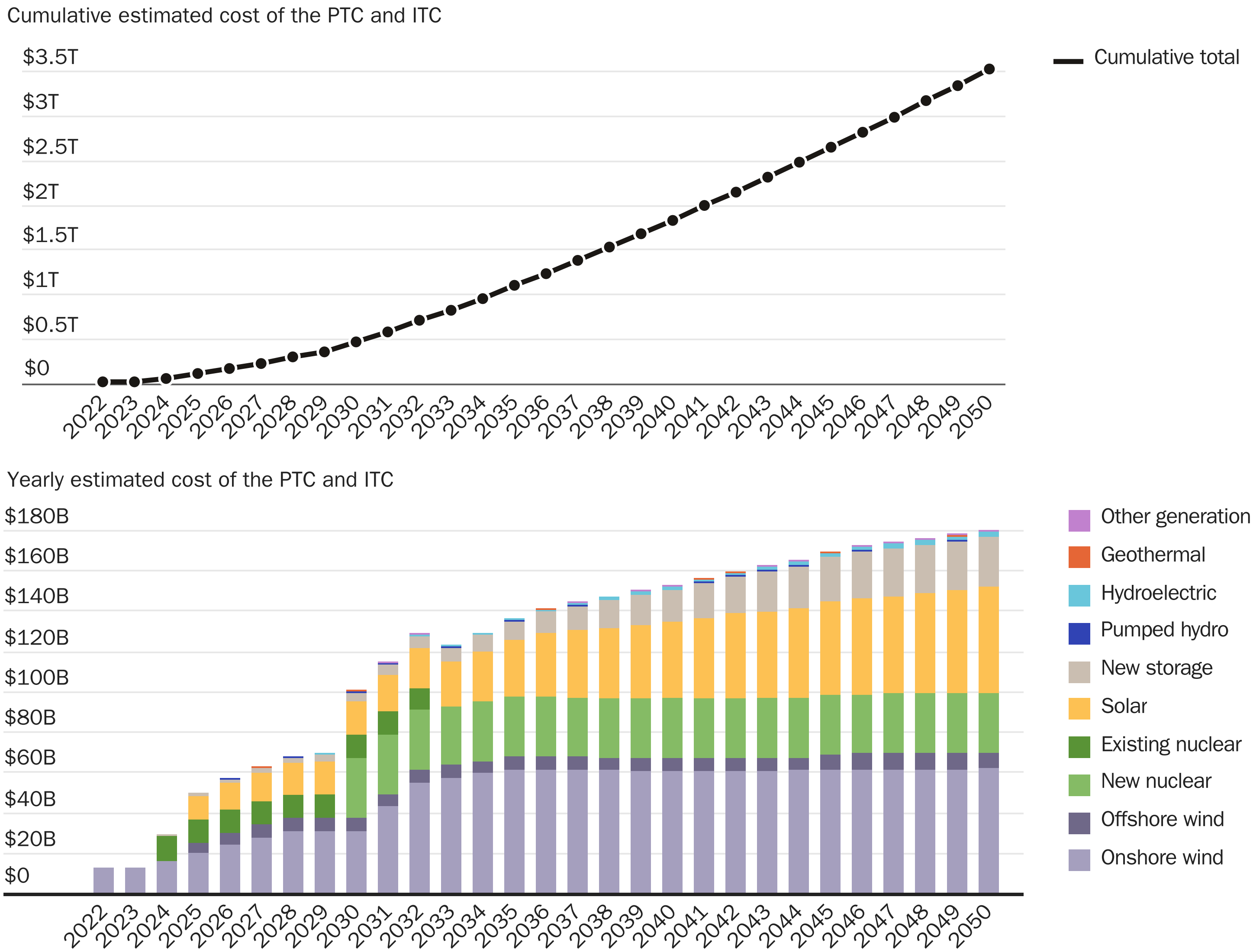
kilowatt.[48] To derive tax credit spending amounts, we apply a 30 percent ITC to the level of new investment in each year.

New energy storage projects are eligible for only the ITC. The arithmetic for quantifying tax credits under a 30 percent ITC for energy storage is calculated the same way as for offshore wind, with the credit applied to a percentage of the capital investment in eligible projects. Hence the level of the tax credit is based on the project's up-front cost. However, each input for our energy storage projections—total installed capacity and cost per unit—features variability that is difficult to capture in a simple model. We found the EIA's projection of new storage deployment to be implausibly low, even for a lower bound, so we rely instead on the REPEAT Project for a lower-bound estimate of energy storage investment and on NREL for the upper bound. Our estimates account only for the capital costs of battery storage and not total system costs, as formulated by NREL.[49] Opting to use total system costs would increase the ITC costs by approximately $80 billion by 2050, depending on the cost scenario used.[50]

To the best of our knowledge, no one has attempted to estimate the long-term cost of the advanced manufacturing (45X) credit for critical mineral production. The critical

Figure 6

Production Tax Credit and Investment Tax Credit alone could cost over $3 trillion by 2050



Source: Authors' calculations; "Annual Energy Outlook 2023," US Energy Information Administration, March 2023; and Pieter Gagnon et al., "2023 Standard Scenarios Report: A US Electricity Sector Outlook," National Renewable Energy Laboratory, revised January 2024; and REPEAT Project (Rapid Energy Policy Evaluation and Analysis Toolkit), Princeton University; and Ryan Sweezey, "The Indefinite Inflation Reduction Act: Will Tax Credits for Renewables Be Around for Decades?," Wood Mackenzie, March 2023.

Notes: Please contact the authors to request a copy of the underlying datasets we used and to see our calculations. PTC = Production Tax Credit; and ITC = Investment Tax Credit.

mineral provision within section 45X has no expiration date and applies to approximately 50 critical minerals, including some minerals whose domestic production could rise sharply, such as lithium.[51] Similarly, the Electric Power Research Institute estimates that the production tax credits for clean hydrogen (45V) could cost between $385 billion and $756 billion by 2050.[52] These high-end figures are not reflected in our own estimates, but we note them here to illustrate the open-ended nature of IRA spending.

FINDINGS

Within the upcoming 10-year budget window (2025–2034), we estimate the IRA spending will range between $936 billion under a set of lower-bound assumptions and $1.97 trillion under a set of upper-bound assumptions. By 2050, total IRA spending could range between $2.04 trillion and $4.67 trillion. Table 3 shows Cato's estimated total spending on IRA energy subsidies through the upcoming 10-year budget scoring window, as well as through 2050, including present values of IRA spending through 2050 using discount rates of 0, 3 percent, and 7 percent.

The original CBO/JCT 10-year score significantly underestimated the subsidy payments authorized by the IRA, but third-party estimates of the IRA's 10-year budget score—such as the Goldman Sachs estimate of $1.2 trillion—fall comfortably between our lower- and upper-bound estimates for the upcoming 10-year budget window.

Our estimates also reflect total spending through 2050, calculated using present values of projected 2050 spending levels with discount rates of 0, 3 percent, and 7 percent. For example, applying a 3 percent discount rate to upper-bound spending yields a present value of $3.26 trillion, which is approximately 30 percent lower than the undiscounted total of $4.67 trillion. Although we recognize that spending beyond the 10-year budget window is unlikely to be scored as part of budget reconciliation legislation, it is an important consideration as policymakers weigh reform or repeal.[53]

We also note the possibility of applying a longer-term scoring window to match tax cuts with spending cuts beyond the typical 10-year budget window. Because IRA spending on the PTC and the ITC is likely to continue to increase throughout the 2040s, extending the budget window for a reconciliation package beyond the typical 10 years will increase the amount of offsets made available by IRA repeal.

POLICY RECOMMENDATIONS

The federal government passed the largest climate bill in history, vastly underestimated the costs, and subjected taxpayers to unlimited liability. We recommend full repeal of the IRA's energy subsidies. If full repeal is not possible, Congress should limit taxpayer liability by capping the dollar value of subsidies, putting an expiration date on the subsidies regardless of emissions levels, or both. For example, Congress could limit the level of IRA subsidies to the August 2022 CBO and JCT score of $383 billion.

Disparities in cost estimates highlight the need for policymakers to require budget experts at the CBO, JCT, and other government research organizations to publish transparent estimates of the IRA's long-term costs.[54] Given the size and volatility of IRA cost estimates—initial estimates of roughly $370 billion over 10 years have grown to $4.67 trillion by 2050—the forward-looking budget reconciliation score for IRA repeal should be fully transparent and replicable by outside researchers.

Finally, in addition to legislative reform or repeal of IRA spending, the Trump administration should limit the availability of IRA subsidies by unwinding the series of IRS guidance documents that have vastly expanded the cost of

Table 3

Cato's estimate of energy spending in the Inflation Reduction Act

	10-year score	2050 score (no discount)	2050 score (3% discount rate)	2050 score (7% discount rate)
Upper bound	$1.97 trillion	$4.67 trillion	$3.26 trillion	$2.2 trillion
Lower bound	$936 billion	$2.04 trillion	$1.47 trillion	$1.03 trillion

Sources: Authors' calculations; "Annual Energy Outlook 2023," US Energy Information Administration, March 2023; and Pieter Gagnon et al., "2023 Standard Scenarios Report: A US Electricity Sector Outlook," National Renewable Energy Laboratory, revised January 2024.
Note: Please contact the authors to request a copy of the underlying datasets we used and to see our calculations.

the IRA. In addition to the repowering issue outlined above, in December 2024, the IRS extended the section 48E ITC to include components of the transmission system—an action contemplated by Congress that was expressly removed from the climate portion of the Build Back Better agenda.[55] Such IRS guidance is inappropriate; it could fail judicial review and is remediable by the executive branch.

CONCLUSION

The IRA was passed to decarbonize the US economy, and the CBO and the JCT estimated it would cost less than $400 billion over 10 years. Using the methods described above, we estimate far larger costs of up to $1.97 trillion over 10 years and $4.7 trillion by 2050. The American people and our elected representatives cannot make informed decisions about the IRA without an accurate assessment of its cost, and we should not have had to wait two years to understand the IRA's impact on the budget.

Further, Congress should stop issuing blank-check subsidies with no expiration date. The massive cash transfer from taxpayers to private firms under the guise of environmentalism creates an overwhelming and undue burden on taxpayers who continue to pay for fiscally irresponsible federal spending. By nearly any metric, the IRA is a flawed policy that should be repealed.

APPENDIX

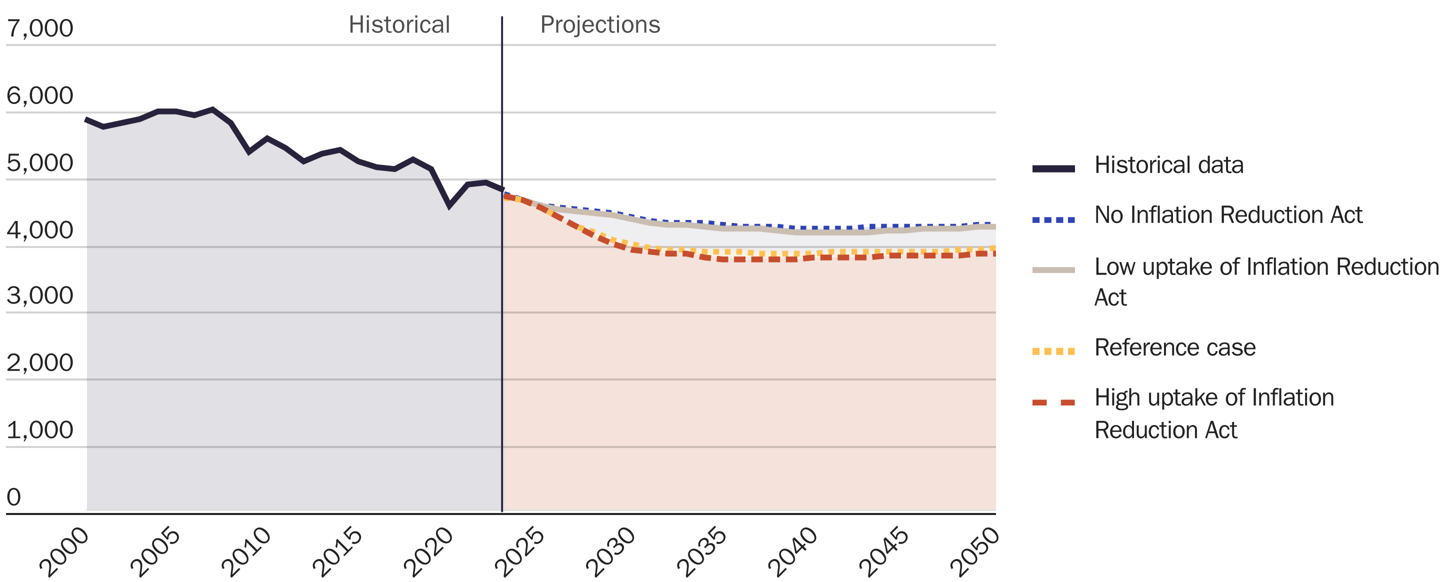
There are significant problems with applying a strict cost-benefit analysis to the IRA. We note that many economists view cost-benefit studies as central to analyzing climate policy, however, and we offer a cost-benefit framework to those economists. In the case of the IRA, both the benefits and the costs are highly uncertain. The uncertainties on the cost side are the subject of this paper. The range of potential benefits is also wide because there is a large range of plausible estimates of the social cost of carbon dioxide (SCC), which is the most readily available estimate of the social benefit of carbon dioxide (CO_2) reduction. The SCC that was estimated by the EPA during President Barack Obama's administration was about $50 per ton, and the EPA's most recently proposed SCC is $190 per ton of CO_2, both of which were estimated using a global scope. In addition to debates about the correct scope to use when estimating the SCC (global versus domestic), there are also valid debates about the appropriate discount rates.[56]

As shown in Figure 7, the EIA's reference case projects that

Figure 7

All-sector emissions

CO_2 emissions, million metric tons



Sources: Authors' calculations; "Annual Energy Outlook 2023: Reference Case Projection Tables, Table 18," US Energy Information Administration, March 2023; and "US Energy-Related Carbon Dioxide Emissions, 2023," US Energy Information Administration, April 2024.

Note: Please contact the authors to request a copy of the underlying datasets we used and to see our calculations.

all-sector CO_2 emissions in the United States will decrease by 0.7 percent annually through 2050. In comparison, in the absence of the IRA, emissions would decline by 0.4 percent annually. In terms of tons of CO_2 rather than percentages, the EIA projects that the IRA will reduce CO_2 emissions by 9.122 billion metric tons by 2050 relative to the no-IRA case.

Applying our lower-bound and upper-bound estimates of the cost of the IRA by 2050, we estimate that the CO_2 abatement cost of the IRA is between $224 and $535 per ton. Different assumptions about the cost of the IRA, its impact on CO_2 emissions levels, and the social cost of CO_2 would yield different results.

NOTES

1. "Read the Letter That Biden Wrote to Say That He Would No Longer Seek Reelection," Associated Press, July 21, 2024.

2. The European Green Deal is likely in second place at about 400 billion euros, but that amount significantly trails the full cost of the IRA, as discussed in this brief. "The European Green Deal: A Growth Strategy That Protects the Climate," European Commission, October 14, 2024.

3. "Roll Call Vote 117th Congress—2nd Session," US Senate, August 7, 2022; and "Roll Call 420 | Bill Number: H.R. 5376," US House of Representatives Clerk, August 12, 2022.

4. Jonathan L. Ramseur, "Inflation Reduction Act of 2022 (IRA): Provisions Related to Climate Change," Congressional Research Service, Report R47262, updated October 26, 2023.

5. Coral Davenport and Lisa Friedman, "'Build Back Better' Hit a Wall, but Climate Action Could Move Forward," *New York Times*, January 20, 2022.

6. Jason Plautz, "House Committee Approves $150B Clean Electricity Performance Program," *Utility Dive*, September 13, 2021; and Ashley J. Lawson, "The Clean Energy Performance Program (CEPP): In Brief," Congressional Research Service, Report R46934, October 7, 2021.

7. Michael F. Cannon, "Medicare Is Not Taxing or Coercing Merck, Just Reducing Its Government Subsidies," *Cato at Liberty* (blog), Cato Institute, June 9, 2023.

8. "Summary: The Inflation Reduction Act of 2022," Senate Democrats, July 27, 2022. The initial estimate of $369 billion excluded certain provisions while also including the Superfund reinstatement under section 13601 of the IRA, which increased credited revenues by approximately $12 billion. The CBO's September 7, 2022, cost estimate states: "JCT estimates that enacting section 13601 will increase revenues credited to the Hazardous Substance Superfund." See "Summary: Estimated Budgetary Effects of Public Law 117-169, to Provide for Reconciliation Pursuant to Title II of S. Con. Res. 14," Congressional Budget Office, September 7, 2022, p. 15.

9. Using 2022 as the baseline rather than a year in the peak-emissions era of 2005–2008 makes a 75 percent reduction much more difficult and places it out of reach in the near term. See "U.S. Energy-Related Carbon Dioxide, 2023," US Energy Information Administration, April 2024.

10. John D. Wilson and Zach Zimmerman, "The Era of Flat Power Demand Is Over," Grid Strategies, December 2023.

11. "AEO2023 Issues in Focus: Inflation Reduction Act Cases in the AEO2023," US Energy Information Administration, March 2023. Twenty-five percent of 1.685 billion metric tons of CO_2 is approximately 0.421 billion metric tons. See Travis Fisher, "New IRS Guidance Makes the Inflation Reduction Act's Energy Subsidies Harder to Eliminate," *Cato at Liberty* (blog), Cato Institute, May 31, 2024.

12. To request a copy of the underlying datasets that we used and to see our calculations, please contact the authors. See row 90 of the lower-bound and upper-bound sheets in our formula workbook.

13. John D. Wilson and Zach Zimmerman, "The Era of Flat Power Demand Is Over," Grid Strategies, December 2023.

14. According to the PJM Interconnection's after-auction report, it appears that every megawatt of coal, oil, and gas offered in the 2025/2026 auction cleared. See "2025/2026 Base Residual Auction Report," *PJM Interconnection*, July 30, 2024, table 6.

15. Electricity-related emissions in Texas are flat or slightly increasing because CO_2 intensity reductions are being offset by load growth. See "Energy-Related CO_2 Emission Data Tables," US Energy Information Administration, October 29, 2024.

16. Mark Takahashi, "PJM Board Response," *PJM Interconnection*, letter to advocates, September 19, 2024.

17. David Jordan, "Trump Vows EPA Rollbacks as Climate Becomes Hot Campaign Issue," *Roll Call*, August 29, 2024.

18. “Joint Statement from Leader Schumer and Senator Manchin Announcing Agreement to Add the Inflation Reduction Act of 2022 to the FY2022 Budget Reconciliation Bill and Vote in Senate Next Week,” Senate Democrats, July 27, 2022; and “Summary: The Inflation Reduction Act of 2022,” Senate Democrats, July 27, 2022.

19. “Summary: Estimated Budgetary Effects of Public Law 117-169, to Provide for Reconciliation Pursuant to Title II of S. Con. Res. 14,” Congressional Budget Office, September 7, 2022; and “Estimated Budget Effects of the Revenue Provisions of Title I—Committee on Finance of an Amendment in the Nature of a Substitute H.R. 5376,” Joint Committee on Taxation, August 9, 2022.

20. Jon Huntley et al., “Senate Passed Inflation Reduction Act: Estimates of Budgetary and Macroeconomic Effects,” University of Pennsylvania Wharton Budget Model, August 12, 2022.

21. Alex Durante et al., “Details & Analysis of the Inflation Reduction Act Tax Provisions,” Tax Foundation, August 10, 2022.

22. William McBride and Alex Muresianu, “Major Takeaways from CBO’s Updated Long-Term Outlook,” Tax Foundation, February 13, 2024.

23. “Update: Budgetary Cost of Climate and Energy Provisions in the Inflation Reduction Act,” University of Pennsylvania Wharton Budget Model, April 27, 2023.

24. John Bistline et al., “Economic Implication of the Climate Provisions of the Inflation Reduction Act,” Brookings Papers on Economic Activity, March 29, 2023.

25. “The US Is Poised for an Energy Revolution,” Goldman Sachs, April 17, 2023.

26. “Estimated Budget Effects of the Revenue Provisions of Title I—Committee on Finance of an Amendment in the Nature of a Substitute H.R. 5376,” Joint Committee on Taxation, August 9, 2022; and “The Budget and Economic Outlook: 2024 to 2034,” Congressional Budget Office, February 2024.

27. Michele Della Vigna et al., “Carbonomics: The Third American Energy Revolution,” Goldman Sachs, March 22, 2023.

28. Laura Feiveson and Matthew Ashenfarb, “The Inflation Reduction Act: Saving American Households Money While Reducing Climate Change and Air Pollution,” US Department of the Treasury, August 7, 2024.

29. “Summary: Estimated Budgetary Effects of Public Law 117-169, to Provide for Reconciliation Pursuant to Title II of S. Con. Res. 14,” Congressional Budget Office, September 7, 2022.

30. “SOI Tax Stats—Clean Energy Tax Credit Statistics,” Internal Revenue Service, 2023.

31. Laura Feiveson and Matthew Ashenfarb, “The Inflation Reduction Act: Saving American Households Money While Reducing Climate Change and Air Pollution,” US Department of the Treasury, August 7, 2024.

32. “Summary: Estimated Budgetary Effects of Public Law 117-169, to Provide for Reconciliation Pursuant to Title II of S. Con. Res. 14,” Congressional Budget Office, September 7, 2022.

33. Ryan Sweezey and Robert Whaley, “The Inflation Reduction Act One Year On,” Wood Mackenzie, August 4, 2023.

34. David Brown, “Hitting the Brakes: How the Energy Transition Could Decelerate in the US,” Wood Mackenzie, May 2024.

35. Erin Boyd, “Power Sector Modeling 101,” US Department of Energy.

36. Further research in this area could incorporate sensitivity analyses based on different scenarios that we did not analyze, including different rates of demand growth or cost-reducing breakthroughs in certain technologies. For example, if the component costs for solar photovoltaics continue to be reduced, deployment levels of solar will be higher than if costs level off (all else being equal). Recent technological advancements in geothermal power plants could also encourage faster wide-scale deployment of that technology. Significant expansion of the transmission system would also accelerate IRA subsidies. There are too many degrees of freedom in the modeling of IRA spending to capture all the relevant pieces in a snapshot.

37. “Solar Investment Tax Credit (ITC),” Solar Energy Industries Association, 2024.

38. Donald J. Marples and Nicholas E. Buffie, “Clean Vehicle Tax Credits,” Congressional Research Service, updated December 26, 2024.

39. Energy storage resources are eligible for the investment tax credit only. Amish Shah et al., “IRS Releases 2023 Section 45 Production Tax Credit Amounts,” Holland & Knight, June 21, 2023.

40. Emma Penrod, “Repowering Will Represent Nearly Half

of All New Wind Capacity in 2024: Enverus," *Utility Dive*, February 22, 2024.

41. Michael Purdie, "How Existing Hydropower Could Benefit from the Inflation Reduction Act," National Hydropower Association, January 8, 2024.

42. Isaac Orr and Mitch Rolling, "The Death of a Wind Farm," *Thinking Minnesota*, Spring 2023.

43. "Data Driven Energy & Climate Policy Evaluation," REPEAT Project (Rapid Energy Policy Evaluation and Analysis Toolkit), Princeton University.

44. To request a copy of the underlying datasets that we used and to see our calculations, please contact the authors.

45. Cy McGeady, "Strategic Perspectives on U.S. Electric Demand Growth," Center for Strategic and International Studies, May 20, 2024. "We assume the tax credits will not phase out before 2050, based on 13 of 17 current policies scenarios in NREL's 2023 Standard Scenarios never reaching the Inflation Reduction Act of 2022's emissions reduction targets." See "Financial Cases and Methods," National Renewable Energy Laboratory, 2024; and Pieter Gagnon et al., "2023 Standard Scenarios Report: A U.S. Electricity Sector Outlook," National Renewable Energy Laboratory, revised January 2024.

46. Short of a catastrophic event that would destroy demand for electricity in the United States, the amount of new, low–greenhouse gas (GHG) electricity production that would be required to reach the Inflation Reduction Act's GHG targets would inevitably yield large subsidy payments.

47. The EIA tends to underestimate growth in new and emerging technologies, largely due to its conservative assumptions about market adoption and innovation, compared to organizations like NREL. This is why we incorporate both EIA and NREL projections in our cost estimates for greater balance.

48. "Cost and Performance Characteristics of New Generating Technologies, *Annual Energy Outlook 2023*," US Energy Information Administration, March 2023.

49. The formula to calculate total system costs according to NREL: Total cost ($/kWh) = energy cost ($/kWh) + power cost ($/kW) / duration (hr).

50. For a fuller discussion of battery cost estimates, see Wesley Cole and Akash Karmakar, "Cost Projections for Utility-Scale Battery Storage: 2023 Update," National Renewable Energy Laboratory, June 2023.

51. We note that unanticipated discoveries of critical mineral deposits in the United States could significantly increase IRA spending under section 45X. See Seth Amgott, "Unlocking Arkansas' Hidden Treasure: USGS Uses Machine Learning to Show Large Lithium Potential in the Smackover Formation," US Geological Survey, October 21, 2024.

52. "Impacts of IRA's 45V Clean Hydrogen Production Tax Credit," Low-Carbon Resources Initiative White Paper, Electric Power Research Institute, November 3, 2023.

53. Andrew R. Garbarino et al., "FINAL Credits Letter," letter to US House of Representatives Speaker Mike Johnson, August 6, 2024.

54. Alex Muresianu and William McBride, "Major Takeaways from CBO's Updated Long-Term Outlook," Tax Foundation, February 13, 2024.

55. See Department of the Treasury, "Definition of Energy Property and Rules Applicable to the Energy Credit," Internal Revenue Service, 26 CFR Part 1, pp. 214–16.

56. Travis Fisher, "The Political Economy of EPA's Updated Social Cost of Carbon," *Cato at Liberty* (blog), Cato Institute, February 28, 2024.

RELATED STUDIES FROM THE CATO INSTITUTE

On Inflation Reduction Act Reform, Anything Short of Full Repeal Is Failure by Travis Fisher, Adam N. Michel , and Joshua Loucks, *Cato at Liberty* (blog) (November 12, 2024)

A Bigger Government Means Giving Up Almost Half Your Paycheck by Adam N. Michel, Policy Analysis no. 981 (October 10, 2024)

Barriers to Energy Supply Are Everywhere—Let's Get Serious About Permitting Reform by Travis Fisher and Joshua Loucks, *Cato at Liberty* (blog) (August 30, 2024)

The Inflation Reduction Act after Two Years: Spending Estimates Reach New Heights, but Green New Deal Supporters Want More by Travis Fisher and Joshua Loucks, *Cato at Liberty* (blog) (August 16, 2024)

Slashing Tax Rates and Cutting Loopholes: Options for Tax Reform in the 119th Congress by Adam N. Michel, Policy Analysis no. 975 (June 17, 2024)

The Power Struggle: Examining the Reliability and Security of America's Electrical Grid by Travis Fisher, Testimony (March 12, 2024)

The Political Economy of EPA's Updated Social Cost of Carbon by Travis Fisher, *Cato at Liberty* (blog) (February 28, 2024)

The Inflation Reduction Act Could Turn Electricity Markets into Subsidy Clearinghouses by Travis Fisher, *Cato at Liberty* (blog) (October 23, 2023)

How Subsidies in the Inflation Reduction Act Undermine Transmission Reform by Travis Fisher, *Cato at Liberty* (blog) (September 22, 2023)

Tax Expenditures and Tax Reform by Chris Edwards, Policy Analysis no. 954 (July 25, 2023)

Department of Energy Loan Programs by Chris Edwards, Testimony (February 15, 2017)

RECENT STUDIES IN THE CATO INSTITUTE POLICY ANALYSIS SERIES

990. **Corporate Welfare in the Federal Budget** by Chris Edwards (March 4, 2025)

989. **Congress Can't Outgrow or Inflate Away the Social Security Financing Problem** by Romina Boccia and Dominik Lett (February 12, 2025)

988. **Subsidizing Transport: How Much Do Taxpayers Pay for Rail, Road, and Air Travel?** by Marc Joffe and Krit Chanwong (January 28, 2025)

987. **A Comprehensive Evaluation of Policy Rate Feedback Rules** by Jai Kedia and Norbert Michel (January 14, 2025)

986. **A Fiscal Agenda for the 119th Congress: The 2025 Fiscal Cliff Calls for Spending Restraint** by Romina Boccia and Dominik Lett (January 7, 2025)

985. **Digital Trade Brings the World to Your Fingertips** by Gabriella Beaumont-Smith (November 26, 2024)

984. **The Social Security Trust Fund Myth: Social Security Is a Legal Ponzi Scheme** by Romina Boccia (November 13, 2024)

983. **Why US Immigration Officials Should Allow "Digital Nomad" Admissions** by Angelo A. Paparelli, David J. Bier, Peter Choi, and Stephen Yale-Loehr (October 29, 2024)

982. **Is There Life After NATO?** by Marc Trachtenberg (October 22, 2024)

981. **A Bigger Government Means Giving Up Almost Half Your Paycheck** by Adam N. Michel (October 10, 2024)

980. **Reforming State and Local Economic Development Subsidies** by Scott Lincicome, Marc Joffe, and Krit Chanwong (September 19, 2024)

979. **Broken Trust: The Pervasive Role of Deceit in American Policing** by Andrew Eichen (September 12, 2024)

978. **Are Carbon Border Adjustments a Dream Climate Policy or Protectionist Nightmare?** by Gabriella Beaumont-Smith (July 30, 2024)

977. **Illegal Immigrant Murderers in Texas, 2013–2022: Illegal Immigrant and Legal Immigrant Conviction and Arrest Rates for Homicide and Other Crimes** by Alex Nowrasteh (June 26, 2024)

976. **Helping Families Navigate the Changing Education Landscape** by Colleen Hroncich and Jamie Buckland (June 25, 2024)

975. **Slashing Tax Rates and Cutting Loopholes: Options for Tax Reform in the 119th Congress** by Adam N. Michel (June 17, 2024)

974. **A Guide to Content Moderation for Policymakers** by David Inserra (May 21, 2024)

973. **A Case for Federal Deficit Reduction Spending Cuts to Avoid a Fiscal Crisis** by Ryan Bourne (April 18, 2024)

972. **Terrorism and Immigration: A Risk Analysis, 1975–2023** by Alex Nowrasteh (April 9, 2024)

971. **A Return to US Casualty Aversion: The 9/11 Wars as Aberrations** by John Mueller (April 2, 2024)

970. **Biden Short-Term Health Plans Rule Creates Gaps in Coverage: Rule Would Deny Care After Patients Fall Ill** by Michael F. Cannon (March 14, 2024)

969. **State Fiscal Health and Cost-Saving Strategies** by Marc Joffe (February 20, 2024)

968. **Bold International Tax Reforms to Counteract the OECD Global Tax** by Adam N. Michel (February 13, 2024)

967. **Containing Medicaid Costs at the State Level** by Marc Joffe and Krit Chanwong (February 6, 2024)

966. **Curbing Federal Emergency Spending Government Spending Grows with Excessive and Wasteful Emergency Designations** by Romina Boccia and Dominik Lett (January 9, 2024)

965. **Taiwan's Urgent Need for Asymmetric Defense** by Eric Gomez (November 14, 2023)

964. **Trade and Investment Are Not a Balancing Act** by Norbert J. Michel (November 7, 2023)

963. **Misperceptions of OPEC Capability and Behavior: Unmasking OPEC Theater** by David Kemp and Peter Van Doren (November 2, 2023)

962. **Are Public School Libraries Accomplishing Their Mission? Public School Libraries Do Not Appear to Stock a Balance of Views** by Neal McCluskey (October 17, 2023)

961. **Pariah or Partner? Reevaluating the US-Saudi Relationship** by Jon Hoffman (September 20, 2023)

960. **Expand Access to Methadone Treatment: Remove Barriers to Primary Care Practitioners Prescribing Methadone** by Jeffrey A. Singer and Sofia Hamilton (September 7, 2023)

959. **Sweden During the Pandemic: Pariah or Paragon?** by Johan Norberg (August 29, 2023)

958. **Terrorism and Immigration: A Risk Analysis, 1975–2022** by Alex Nowrasteh (August 22, 2023)

957. **Corking Russian Gas: Global Economic and Political Ramifications** by Scott Semet (August 17, 2023)

956. **A Link Tax Won't Save the Newspaper Industry: The Journalism Competition and Preservation Act Will Neither Promote Competition nor Preserve Newspapers** by Paul Matzko (August 14, 2023)

955. **Freeing American Families: Reforms to Make Family Life Easier and More Affordable** by Vanessa Brown Calder and Chelsea Follett (August 10, 2023)

954. **Tax Expenditures and Tax Reform** by Chris Edwards (July 25, 2023)

953. **2022 Arms Sales Risk Index** by Jordan Cohen and A. Trevor Thrall (July 18, 2023)

952. **Adverse Effects of Automatic Cost-of-Living Adjustments to Entitlement and Other Payments** by John F. Early (June 22, 2023)

951. **Indian Nationalism and the Historical Fantasy of a Golden Hindu Period** by Swaminathan S. Anklesaria Aiyar (June 21, 2023)

950. **Why Legal Immigration Is Nearly Impossible: US Legal Immigration Rules Explained** by David J. Bier (June 13, 2023)

949. **Global Inequality in Well-Being Has Decreased across Many Dimensions: Introducing the Inequality of Human Progress Index** by Chelsea Follett and Vincent Geloso (June 8, 2023)

948. **The High Price of Buying American: The Harms of Domestic Content Mandates** by James Bacchus (June 6, 2023)

947. **The Future of the WTO: Multilateral or Plurilateral?** by James Bacchus (May 25, 2023)

946. **Course Correction: Charting a More Effective Approach to US-China Trade** by Clark Packard and Scott Lincicome (May 9, 2023)

945. **The Right to Financial Privacy: Crafting a Better Framework for Financial Privacy in the Digital Age** by Nicholas Anthony (May 2, 2023)

944. **Balance of Trade, Balance of Power: How the Trade Deficit Reflects US Influence in the World** by Daniel Griswold and Andreas Freytag (April 25, 2023)

943. **Streamlining to End Immigration Backlogs** by David J. Bier (April 20, 2023)

942. **Transforming the Internal Revenue Service** by Joseph Bishop-Henchman (April 11, 2023)

CITATION

Fisher, Travis, and Joshua Loucks. "The Budgetary Cost of the Inflation Reduction Act's Energy Subsidies: IRA Energy Tax Credits Could Cost $4.7 Trillion by 2050," Policy Analysis no. 991, Cato Institute, Washington, DC, March 11, 2025.

SAFE
1111 19th Street, NW
Suite 406
Washington, DC 20036
Tel: 202.461.2360
Fax: 202.461.2379
Web: secureenergy.org

The Honorable Brett Guthrie
Chairman, House Committee on Energy & Commerce
2125 Rayburn House Office Building
45 Independence Avenue SW
Washington, D.C. 20515

The Honorable Frank Pallone
Ranking Member, House Committee on Energy & Commerce
2125 Rayburn House Office Building
45 Independence Avenue SW
Washington, D.C. 20515

Re: Full Committee Hearing – *Converting Energy into Intelligence: The Future of AI Technology, Human Discovery, and American Global Competitiveness*

Dear Chairman Guthrie and Ranking Member Pallone,

As Executive Director of SAFE's Center for Grid Security, I commend the House Energy & Commerce Committee for holding this timely hearing on the intersection of energy, artificial intelligence (AI), and American competitiveness. Ensuring the United States maintains its global lead in these areas requires more than innovation—it demands action to modernize and expand our energy infrastructure at the speed of national urgency.

AI is reshaping warfare, industrial productivity, and global markets. As recognized by this Committee, AI's transformative power also comes with unprecedented energy demands. The nation's current generation and linear energy infrastructure, such as transmission lines and pipelines, is not equipped to support the scale, speed, or security these technologies require—particularly as they become critical to national defense and industrial output.

To support American leadership in AI, the Center for Grid Security urges the Committee to consider the following critical actions to strengthen our grid energy posture:

1. **Expand Transmission Infrastructure**

A secure, AI-capable grid requires a robust national transmission system that can move power flexibly and efficiently to remote locations where data centers are often located. Long distance lines, interregional connections, and grid-enhancing technologies must be rapidly deployed to meet the needs of industry, communities, and the military.

SAFE

1111 19th Street, NW
Suite 406
Washington, DC 20036

Tel: 202.461.2360
Fax: 202.461.2379
Web: secureenergy.org

2. Accelerate Deployment of All Forms of Domestic Energy

From fossil fuels to clean energy, every form of American energy has a role to play in supporting AI and economic resilience. We must unlock new natural gas, advanced nuclear, solar, hydrogen, and battery storage projects—especially those located near major data center corridors and defense installations. To achieve this, we must avoid limiting our policy framework to picking winners and losers among the numerous generation technologies available to American power producers. Capitalizing on the full spectrum of abundant American energy resources will ensure we meet growing demand with the speed and scale required.

3. Prioritize AI's Strategic and Defense Energy Requirements

AI systems are powering decision-making, threat detection, cyber defense, and logistics across every branch of the military. A blackout or energy disruption could now jeopardize not just economic activity—but also mission readiness. Energy access for AI must be viewed as a national defense imperative.

4. Advance Comprehensive Permitting Reform

Outdated, overlapping, and uncertain permitting processes are among the greatest obstacles to building the energy future AI demands. Congress must modernize these processes to allow for timely review and construction of transmission lines, generation resources, and energy storage assets.

Without swift and bold action, the United States risks ceding energy and technological leadership to adversaries. But with pragmatic policy—grounded in security, speed, and dominance—we can build a grid that powers both prosperity and protection.

Thank you for your leadership, and for the opportunity to submit this letter for the record.

Sincerely,

Danielle Russo
Executive Director
Center for Grid Security, SAFE

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

Eliza Martin
Ari Peskoe

March 2025

ENVIRONMENTAL & ENERGY LAW PROGRAM
HARVARD LAW SCHOOL

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.

Table of Contents

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

---

* Eliza Martin is a Legal Fellow in the Environmental and Energy Law Program at Harvard Law School. Ari Peskoe is the Director of the Electricity Law Initiative. We thank Kent Chandler, Josh Macey, Abe Silverman, and Megan Wachspress for thoughtful feedback on our draft.

[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).

Exclusive: Micron to impose tariff-related surcharge on some products from April 9, sources say

By **Reuters**

April 8, 2025 8:08 AM EDT · Updated 10 hours ago

Aa

SHANGHAI/TAIPEI, April 8 (Reuters) - U.S. memory chipmaker Micron Technology (MU.O) has told U.S. customers it plans to impose a surcharge on some products from Wednesday to account for U.S. President Donald Trump's new tariffs, four sources familiar with the matter said.

Micron's overseas manufacturing sites are largely based in Asia, including China, Taiwan, Japan, Malaysia and Singapore.

The company notified its customers in a letter that while Trump's announcement last week exempted semiconductors, which account for part of Micron's portfolio, the tariffs applied to memory modules and solid-state drives (SSDs), the sources said.

Those products, used to store data in various products from cars to laptops and data center servers, would now be subject to a surcharge, they said.

Micron did not immediately respond to a request for comment.

The notice to customers echoes comments the company made on March 21 on a post-earnings call, when its executives said it intended to pass along costs to customers in areas where tariffs had an impact.

It also comes shortly after Micron in late March notified customers of price rises due to an increase in "un-forecasted demand" for its products.

Trump's announcement last week jolted economies around the world, triggering retaliatory levies from China and sparking fears of a global trade war and recession.

It has also forced companies globally to assess whether they should absorb the tariffs or shift them on to customers.

U.S. customs agents began collecting Trump's unilateral 10% tariff on all imports from many countries on Saturday. Higher "reciprocal" tariff rates of 11% to 50% on individual countries are due to take effect on Wednesday at 12:01 a.m. EDT (0401 GMT).

An executive at an Asian NAND module manufacturer said they were taking a similar approach to Micron to tell U.S. customers they had to figure out the tariffs themselves.

"If they don't want to bear the taxes, we cannot ship the products. We cannot be held accountable for the decisions made by your government," the person said, declining to be named as they were not permitted to speak to the media.

"With this kind of tax rate, no company can generously say, 'I'll take on the burden'."

Reporting by Brenda Goh in Shanghai, Wen-Yee Lee in Taipei, Fanny Potkin in Singapore and Che Pan in Beijing; Editing by Miyoung Kim and Jan Harvey

Suggested Topics:

Technology

POLITICOPRO

Why Trump's tariff and tax policies could derail efforts to boost US power supply

Despite the president's support for lower energy costs, his recent actions could cause electricity prices to soar.

BY: **CATHERINE MOREHOUSE** | 04/08/2025 05:00 AM EDT

President Donald Trump speaks to members of the media before boarding Marine One on the South Lawn of the White House on Thursday. Trump spoke a day after announcing sweeping new tariffs targeting goods imported to the U.S. on countries including China, Japan and India.| Andrew Harnik/Getty Images

President Donald Trump's tariffs and threatened repeals of clean energy tax credits could undermine efforts to build desperately needed power generation in the United States — and his own policy promises.

The president promised to lower energy prices and declared an "energy emergency" to make it easier to rapidly build new power plants, partly to meet rising demand from data centers and artificial intelligence. His gutting of Biden-era emissions regulations and exploring the possibility of building new plants alongside data centers are aligned with his goals.

But other Trump policies could work against his goals and cause electricity prices to soar. Trump's headline-making tariffs are likely to make it more difficult to secure the materials needed for new power plants and grid projects at affordable prices. And his plans to repeal tax credits are threatening the private sector investment required to bring more power onto the grid.

"Trump's declared an 'energy dominance' agenda, but his campaign promise to repeal tax credits and impose tariffs broadly creates significant uncertainty — if not direct risk — to power plant developers," said Timothy Fox, managing director of power sector coverage at research firm ClearView. "And as a consequence, these efforts could exacerbate the risk of resource inadequacy — but could also accelerate rising power prices throughout the U.S."

Grid operator and utility projections predict the U.S. will need 128 gigawatts more power capacity in the next five years alone. Trump sees preserving existing fossil fuel-fired power plants by reversing rules limiting their greenhouse gas emissions and undoing the core scientific finding that carbon dioxide pollution endangers human health and welfare that has supported federal climate policies for 15 years as part of the solution.

But the president's sweeping tariffs threaten to send prices for basic grid components like transformers skyrocketing, and will likely worsen the already clogged supply chain for gas turbines and other critical grid equipment.

"If [the tariffs] affect the price of bulk power system components — particularly transformers and switching equipment, etc. — that is going to be reflected in the price signal we're going to have to send to induce new generation," Manu Asthana, CEO of the PJM Interconnection, the largest grid operator in the country, said Wednesday at an Electric Power Supply Association event.

The White House did not respond to requests for comment.

For years, utilities have been warning about shortages for basic grid components like transformers, which are critical to transferring power from high-voltage lines to distribution centers that power homes and businesses.

Those shortages have been exacerbated by widespread grid damage caused by hurricanes and wildfires. Lead times for transformers spiked from around 50 weeks in 2021 to an average of 120 weeks last year, according to research firm Wood Mackenzie, and only about 20 percent of transformer needs can be met by a domestic supply chain.

The nation's largest gas turbine manufacturers have also already been grappling with a growing backlog of customers and tight supply chains amid increasing demand for gas plants to meet rising electricity loads.

GE Vernova's backlog for gas equipment will grow "considerably" this year even as it ramps up efforts to create more capacity, the company reported during its earnings call in January — well before Trump's tariffs announcements. Diversifying its turbine supply will help the manufacturer increase its shipment levels, which GE Vernova expects to reach 20 GW by 2027. But the manufacturer cautioned it won't be able to ramp up much more than that.

GE, the largest gas turbine company in the world, did not respond to a request for comment on how the tariffs will impact its supply chains.

Christian Bruch, CEO of Siemens Energy, another major manufacturer of gas turbines and critical electric components, said in a statement the company needs time to "diligently assess the potential impact on Siemens Energy."

"For the time being, it is unclear whether the tariffs will equally impact our competitors," he said. "Overall, regarding the US market, we remain optimistic and expect more opportunities than risks."

Utilities and electric manufacturing groups have urged more balance in the Trump administration's approach to tariffs in light of growing supply chain challenges.

"We would really like the administration to understand that as much as we want ... some critical supply chains to move, that doesn't happen overnight," said Debra Phillips, president and CEO of the National Electrical Manufacturers Association, on a press call Friday. "We need transition periods to bring some of those supply chains back, and we're prepared to be a partner in doing that."

Scott Aaronson, senior vice president of energy security and industry operations at utility trade group Edison Electric Institute, similarly urged striking a balance between pursuing energy dominance and energy security.

"Our industry must have access to the critical components, commodities, and equipment needed to operate the grid, as we work to meet growing customer demands for reliable, affordable, and resilient clean energy," he said in a statement.

Trump's commitment to rolling back Biden-era clean energy tax credits also threatens the financing for wind, solar and battery storage resources waiting to connect to the power grid and capital certainty for future commercial-scale carbon capture, advanced nuclear and geothermal projects.

"How are you going to raise capital for an expansion plan for a solar platform ... when every day you have a new headline about the [Inflation Reduction Act's] durability?" asked Josh Price, director of energy at analysis firm Capstone. "There's just a lot of uncertainty that also makes it really hard to commit to make investment decisions."

Gas is projected to meet just 46 GW of the projected 128 GW of new demand coming online in the next five years, creating a supply gap that the clean energy industry says can be met by the huge amount of renewables waiting to connect to the grid. There were 2.6 terawatts of resources in the queue as of 2023, according to the latest research from Lawrence Berkeley National Laboratory, the vast majority of which is solar, wind and storage.

Increasingly, utilities and grid operators are looking at squeezing more capacity out of existing nuclear and natural gas plants to get more power onto the grid at a faster pace. In PJM, an effort to fast-track certain power projects onto the grid yielded 47 proposals to increase capacity at existing power plants — half of the total projects proposed.

But those efforts are relatively small compared with the amount of power needed to meet rising demand from data centers, electrification and domestic manufacturing, according to Rich Powell, CEO of the Clean Energy Buyers Association, which represents some of the largest tech companies in the country. Without tax credits and finance certainty, the U.S. could lose gigawatts of projects that would otherwise connect to the grid.

"I keep coming back to the basic math. You've got all these sliver solutions. But then the thing that can probably deliver 50 to 100 gigawatts ... is all of these solar and wind projects that are already in the queues,” said Powell. “If we can just get them online, that would be the single biggest chunk" of power capacity that could connect to the grid.