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Provide the docket's number.	E002/TL-26-135

Leave a comment on the docket. *

Minnesota Public Utilities Commission
To Whom it May Concern,

I am a resident of Pine Island, MN and a homeowner. I would like to submit my comment for record on MPUC Docket No. E002/TL-26-135. After careful review of this docket, I have formulated a few concerns regarding Project Skyway. My first concern is for the two residences located between 301 and 500 feet of the Project.

The docket states that the construction would add a minimal aesthetic impact on these residences. I think these homeowners are owed an explanation of just exactly how this is going to impact them, considering how close construction is going to be conducted near them. The docket states that most impacts would be minimal and temporary during the construction phase of the Project and that temporary impacts may include tree clearing, use of heavy equipment (noise and fugitive dust), and lighting that may disturb wildlife, habitat, natural areas, and user enjoyment. The estimated time of construction is 2.5 years and that approximately 20 to 30 daily contract workers will be employed for the construction of the transmission line. That seems like a highly disruptive change for these homeowners to endure for over two years.

Another concern I have is the resulting costs Project Skyway will have on Pine Island residents and business owners. More transmission lines cause utility rates to rise in the short term. The initial construction costs of these multi-billion-dollar projects are passed on to consumers through fixed monthly transmission and rider fees on utility bills. What reassurance do we have that Google fully intends to assume these costs? Will residents and business owners be shouldering these costs? Inflation has already negatively impacted so many people. A rise in utilities short or long term is a very serious concern for people already struggling to pay their bills. Given that this project is to support the construction of a data center, there is a heightened concern about potential rises in utility costs associated with the increased electricity demand. Residents and business owners are owed a thorough explanation of how Project Skyway and the data center are going to impact our

short and long term utility costs.

This is an article from the Center on Global Energy Policy that discusses rising electricity prices associated with data centers and inefficient infrastructure planning:

<https://www.energypolicy.columbia.edu/publications/electricity-affordability-and-load-growth-diagnosing-and-fixing-the-problem/>

This is an article from the Environmental and Energy Study Institute discusses increased energy bills due to data center power demands:

<https://www.eesi.org/articles/view/data-center-power-demands-are-contributing-to-higher-energy-bills>

It states that according to the U.S. Energy Information Administration, residential electricity prices rose by 11.5% in 2025, outpacing inflation. Looking further ahead, prices are expected to increase by up to 40% by 2030 compared to 2025. I understand that Project Skyway is a profitable venture for some, however, the residents and business owners of Pine Island will not see any benefit from this project or the data center. If anything, the evidence points to an increase in utility costs and a major disruption for residents due to long term construction.

– Tosca Wohl

Power Sector

Electricity Affordability and Load Growth: Diagnosing and Fixing the Problem

Commentary by Robin Millican, Douglas J. Arent & David Sandalow • June 23, 2026

This commentary is part of the Electricity Price Research Initiative and was made possible with support from Google.org. It represents the research and views of the author. It does not necessarily represent the views of Google.org, the Center on Global Energy Policy, or Columbia University. The piece may be subject to further revision. More information is available at Our Partners.

- Rising electricity prices reflect a convergence of long-standing system weaknesses, including inefficient infrastructure planning, misaligned utility incentives, slow permitting, supply chain inflation, and reactive climate risk management. Increasing electricity demand, or load growth, including from data centers, is accelerating these pressures.
- Whether load growth raises or lowers prices depends on tariff design, cost allocation, and supply availability. Where low-cost supply is

available and existing infrastructure is efficiently utilized, additional demand can lower per-unit costs; where supply is constrained or capital needs are high, demand can raise prices.

- Optimization of the existing US power system through grid-enhancing technologies, demand response, and large-load flexibility could quickly unlock supply in the form of underutilized capacity. These efforts could defer costly infrastructure buildout but are under-deployed due to regulatory and incentive barriers that favor capital investment over system optimization.
- Sustained cost control will require structural reforms across three areas: realigning utility incentives with cost efficiency rather than capital investment; ensuring that large new loads bear a fair share of system costs at both the federal and state level; and removing the interconnection and permitting bottlenecks that prevent price signals from translating into deliverable supply.

Concerns about electricity affordability in the United States have been rising along with prices. The problem reflects a convergence of pre-existing structural failures: inefficient infrastructure planning, utility incentive structures misaligned with cost efficiency, chronic undervaluation of flexibility in grid operations, slow permitting timelines that have not improved in decades, and storm damage and wildfire costs—both worsening with climate change. Higher electricity demand, or load growth, including from data centers, is accelerating all of these pressures, and adding some of its own.

This commentary draws on recent research and discussions on electricity affordability, including a new analysis from Lawrence Berkeley National Laboratory (LBNL) and The Brattle Group^[1] and a roundtable series the

Center on Global Energy Policy (CGEP) at Columbia University SIPA held in New York, Washington DC, and Austin in late 2025 and early 2026.[2] It examines the structural roots of rising electricity prices and identifies near- and medium-term solutions available to federal and state actors as well as the need for long-term proactive storm-, wildfire- and cyber-related risk reductions.

The central finding is that rising electricity prices are driven by structural features of the power system rather than demand growth alone, and that affordability outcomes under increasing load will depend on how effectively supply, infrastructure, and cost allocation are managed.

Current and Forecast Prices, and Drivers

A new analysis from LBNL provides important grounding on the drivers of electricity pricing in the United States. From 2019 to 2024—a period during which inflation in the United States reached the highest level in 40 years and became a top-tier political issue—average residential retail electricity prices roughly tracked the rate of inflation.[3] Last year marked a departure from this trend, when the average residential retail price of electricity in the United States rose by 6 percent in nominal terms, more than twice the rate of inflation—and by 2.6 percent in real terms.[4]

Primary year-over-year price drivers in 2025, reported in the LBNL analysis, include increases in fuel and wholesale supply costs (a factor in 21 states), distribution cost growth (16 states), generation capital expenditure (11 states), transmission infrastructure costs (11 states), and storm cost recovery (9 states). Annual investor-owned utility (IOU)

generation capital expenditure, for example, increased 22 percent in inflation-adjusted terms in 2025 alone, following 13 percent increases in each of the two prior years.[5]

A particularly underappreciated contributor to electricity price increases mentioned in the LBNL study is equipment cost inflation. Since 2019, producer prices for transformers have risen 89 percent, switchgear 77 percent, and wire and cable 152 percent. These cost increases flow directly into utility capital expenditures and, with a regulatory lag, into customer bills over asset lifetimes.

One of the most consequential findings from the LBNL analysis concerns load growth itself: whether load growth raises prices for existing customers is not predetermined. The direction and magnitude of the effect depend on tariff design, cost allocation, and the adequacy of available supply. States with the highest demand growth from 2019 to 2025 generally saw all-sector average, inflation-adjusted prices decline by more than one cent per kilowatt-hour, as fixed infrastructure costs were spread over a larger consumption base. Nebraska, New Mexico, and North Dakota all absorbed large industrial and data center load additions while reducing inflation-adjusted retail prices. Two factors drove this: 1. abundant low-cost wind and solar generation served new load at below-system-average incremental cost, and 2. substantial commercial and industrial growth spread existing fixed infrastructure costs over more demand, reducing per-unit prices for all customers including residential ratepayers.

That said, early 2026 data show prices climbing broadly, with increases particularly concentrated in the PJM Interconnection (13 states in the mid-Atlantic and Midwest, and Washington DC) and the Southeast. LBNL

found that IOUs filed \$18 billion in rate increase requests in 2025—the highest level since the mid-1980s. Regulators approved, on average, 64 percent of those requests over the past five years, with 2025 running at 66 percent.

Much of that cost has not yet reached customer bills but will in the coming years. That burden has also fallen unevenly: the Energy Information Administration's data show that residential customers saw roughly 27 percent higher bills from 2019 to 2024, compared to approximately 19 percent for commercial and industrial customers—a disparity driven in part by utility cost-allocation methods that have historically shielded large commercial users from proportionate cost recovery.[6]

With roughly one-third of American households dedicating more than 5 percent of their income to electricity, according to LBNL, calls for action are certain to grow.

Near-Term Opportunity: Optimizing Existing Infrastructure

The aforementioned CGEP electricity affordability roundtables that included stakeholders from government, industry, finance, academia, and think tanks consistently surfaced this multifactor diagnosis of the drivers of price increases. However, a recurring theme from the roundtables, and one with a strong near-term political and economic case, is that the United States has substantial untapped capacity in its existing transmission infrastructure. New supply and delivery infrastructure will require years of permitting, siting, and construction; in

the interim, tools including commercially available grid-enhancing technologies (GETs) and demand response can provide a faster and lower-cost path to meaningful capacity increases.

CGEP recently published a white paper examining the evidence base for GETs.[7] A leading GET example is dynamic line rating (DLR), which uses real-time weather and sensor data to determine actual line capacity rather than relying on conservative static assumptions. DLR reduced congestion by up to 65 percent on monitored lines at PPL Electric in Pennsylvania, delivering over \$50 million in congestion cost savings.[8]

The UK's National Grid announced deployment of DLR across 275 kilometers of its transmission infrastructure—driven in part by the need to relieve growing congestion on corridors connecting Scottish wind generation to demand centers in London. The company said this deployment has the potential to enable service to approximately 75,000 additional homes and generate an estimated £20 million per year in consumer savings.[9]

Advanced power flow control devices, which reroute electricity from congested lines to underutilized parallel routes, freed 2 gigawatts (GW) of additional capacity on National Grid's UK system—equivalent to roughly two million homes—saving customers £390 million over seven years.[10]

And advanced conductors, some of which replace steel cores with carbon fiber composites, can nearly double line capacity without new towers or rights-of-way, with deployment timelines measured in months rather than the decade-plus required for new transmission.[11]

All told, the savings realized from GETs could be substantial: analysis in *Proceedings of the National Academy of Sciences* projects \$180 billion in savings by 2050 from strategic deployment of GETs across the United States.[12]

Grid-enhancing technologies address the supply and delivery side of the equation. On the demand side, large-load flexibility—particularly data center load shaping, or reducing usage during peak periods—offers a complementary lever for managing peak demand without relying on high-cost, low-utilization generation. The DCFlex initiative—a collaboration of 53 utilities, grid operators, and hyperscalers—has completed proof-of-concept pilots in Arizona, North Carolina, and France demonstrating that data centers can curtail or shift computational workloads in response to grid signals during peak hours. [13] The DCFlex Arizona project achieved 10 to 40 percent flexibility in workload during a simulated peak event.

Given the potential benefits to the system, regulators are beginning to evaluate new constructs to drive uptake of GETs, demand response, and flexibility. Near-term actions to mandate consideration of GETs in planning processes—as FERC Order 1920 did in 2024—and to require disclosure of transmission utilization rates would represent meaningful progress toward accountability without requiring fundamental restructuring of the regulatory compact. More broadly, these measures point toward a pragmatic near-term strategy for electricity affordability: maximizing the performance of existing infrastructure while longer-term generation and transmission buildout proceeds.

Medium-Term Agenda: Structural Reform

The transition from slow or very low growth to a new era of accelerated load growth, particularly driven by data centers and advanced computing, has exposed structural limitations in how the US power system is governed, planned, and operated. GETs and demand response and flexibility address near-term capacity constraints, but affordability over time requires tackling the deeper structural misalignments that the LBNL analysis and the CGEP roundtables identified.

Several reform priorities have emerged repeatedly in both the literature and practitioner discussions: realigning utility incentives, modernizing cost allocation for a new era of large and concentrated loads, and removing the institutional barriers that prevent price signals from translating into deliverable supply.

Aligning Utility Incentives with Cost Efficiency

The barriers to broader use of tools like GETs and demand response are not technological but institutional and structural. Under traditional cost-of-service regulation, utilities earn authorized returns on equity of approximately 9 to 10 percent—a return structure that applies to transmission owners as well as distribution utilities. This regulatory structure rewards capital deployment more than system optimization. As long as frameworks remain oriented toward proving “need” for new capital investment rather than systematically evaluating lower-cost alternatives, the pace of deployment will lag.

Performance-based regulation (PBR)—which ties utility returns to measurable outcomes like system cost reduction, interconnection speed, and congestion relief—is a commonly proposed structural remedy, including at CGEP's roundtables, but data are still being assembled on its effectiveness at cost management. The UK's experience with PBR under Ofgem's RIIO framework represents the most developed implementation, with some evidence of cost discipline, though results have been mixed and the institutional context differs substantially from the United States. [14] Domestic experience with PBR is limited. New York's Reforming the Energy Vision (REV) initiative is the most prominent US effort, and its track record is still being assessed.

Allocating Costs Fairly as Demand Patterns Shift

The arrival of data centers and other large, concentrated loads is testing cost allocation frameworks at every level of the system. Whether this new demand raises or lowers prices for existing customers depends not on the scale of the load itself but on how the costs of serving it are structured and distributed, according to the recent LBNL analysis and an earlier paper from the Electric Power Research Institute.[15]

At the federal level, FERC is addressing the transmission side of this question. The Commission's advance notice of proposed rulemaking on large load interconnection (RM26-4) proposes that large-load customers bear the full cost of network upgrades their projects trigger—shifting those costs to the interconnection customers who cause them rather than socializing them across all ratepayers. This approach would shield existing customers from bearing the infrastructure burden of new large loads, though it raises a legitimate design question: how to credit the

original payer when upgrades they trigger deliver broader system benefits over time. FERC expects to act on this rulemaking by June 2026.

Separately, state commissions are grappling with large-load retail tariff design. Emerging approaches such as take-or-pay contract structures (which require a buyer to pay for a minimum amount of a product, regardless of actual usage), upfront financial commitments, exit fees, and load flexibility requirements, can in principle protect residential ratepayers while accommodating new large loads.

Early utility projections are encouraging. Indiana utility NIPSCO projects \$7 to \$9 per month in residential savings by 2032 under its Amazon data center agreements;^[16] and Detroit-based DTE estimates a potential 8 percent reduction in residential costs under conditionally approved data center contracts.^[17]

But LBNL notes that these are forward-looking projections, not realized outcomes, and that new tariff structures carry a real risk of insufficient cost protection. A 2025 Harvard Law School review of nearly 50 regulatory proceedings on data center rates questioned the ability to isolate data center energy costs from consumer bills and suggested that details of contract structures be transparent and rigorously evaluated.^[18] Once established, state commissions will need to actively monitor these structures to verify whether projected savings materialize.

Translating Price Signals into Deliverable Supply

A third area for structural reform is removing supply delivery bottlenecks. In PJM Interconnection, rapid data center growth is colliding with supply and transmission constraints, driving capacity auction prices to historic

high. According to LBNL, capacity payments alone are expected to add roughly 1.5 cents per kilowatt-hour (kWh) to PJM wholesale costs across 2025 and 2026. Nationally, LBNL estimates capacity payments added nearly 1 cent/kWh to average wholesale costs in 2025, with a further 0.6 cents expected in 2026.

While the capacity market is pricing scarcity correctly, the broader system cannot respond at the required speed. Interconnection and new-build transmission timelines that take years sever the link between price signals and supply entry. Higher capacity prices mostly end up paying existing generators more rather than inducing new construction, and those extra costs are passed on to consumers through their electricity bills over time.

Addressing this bottleneck requires reforms on two parallel fronts: improving the speed and discipline of interconnection processes, while reducing the time required to permit and build new infrastructure.

The interconnection queue—the process by which new generation and storage projects are studied and approved for grid connection—can be reformed through such efforts as readiness-based prioritization, standardized study processes, and enforceable timelines to reduce delays and bring viable projects online faster. Cluster-based interconnection studies—where projects in a geographic area are evaluated together and required system upgrade costs are shared across entrants rather than borne entirely by the first mover—are another structural reform option. Cluster studies and other queue prioritization reforms were incorporated in FERC Order 2023, though implementation has been slow and uneven. The rule is likely to improve queue efficiency

over time but will not by itself resolve the gap between demand growth and the pace of deliverable supply.[19]

Texas has moved furthest in the direction of queue reform: ERCOT's SB6 framework passed in 2025 introduced approximately \$50,000 per megawatt in non-refundable interconnection fees, financial security requirements, and a tiered queue process designed to prioritize projects with demonstrated readiness and screen out speculative entries that clog studies without ever reaching construction.

More broadly, permitting timelines for new transmission have not materially improved in decades: the average transmission project takes a decade to complete, new high-voltage line construction has fallen to roughly 20 percent of early-2010s levels, and the federal government's authority to site interstate corridors remains limited and contested.[20] Federal and state siting reforms—including streamlined environmental review, categorical exclusions for lower-impact projects, and clearer federal authority for interstate transmission corridors—can help more quickly translate price signals into actual supply additions.[21]

Long-Term Need: Risk Management

Storm cost recovery is emerging as a meaningful retail price driver across multiple states, with LBNL documenting surcharges of 1–3 cents/kWh in places such as Florida in the 2024–2025 period, and multiyear securitization of storm costs. These are not low-probability events—they are recurring, compounding costs that have been and will be embedded in the rate base for decades.

In California, LBNL finds wildfire mitigation and related costs added about 4 cents/kWh from 2019–2024, making them one of the largest contributors to recent rate increases. However, ex-ante resilience investment is demonstrably cheaper than ex-post investment. For example, an analysis from the Energy Institute at UC Berkeley found that the cost of ignitions caused by vegetation striking powerlines would have been 4.5 times greater in 2022 and 2023 absent the California utility PG&E's proactive risk reduction efforts.[22]

Hardening transmission lines in high-risk corridors and accelerating undergrounding in fire-prone areas can reduce long-run costs to ratepayers by lowering the frequency and severity of damage and associated recovery costs, even if they increase near-term capital expenditure. Similarly, expanding interregional transmission to enable reserve-sharing requires upfront investment and coordination but can reduce system costs over time by improving resource utilization and avoiding duplicative capacity buildout.[23]

Another structural liability affects some Western states: utilities bear wildfire liability even absent negligence, creating a material disincentive to build the transmission infrastructure. Federal reinsurance mechanisms or carefully designed liability caps (limited to cases without negligence and conditioned on demonstrated hardening standards) merit serious consideration—not as regulatory relief for utilities but as a risk-allocation reform that avoids the current dynamic in which ratepayers absorb multidecade recovery costs without any coordination or pooling of risk across jurisdictions.

Cybersecurity presents an additional and growing dimension of system risk and will require ongoing diligence. As the number of interconnected

devices (“the internet of energy things”)—advanced sensors, distributed energy resources, cloud-based control architectures, and real-time communications networks—expands, vulnerabilities grow exponentially. Ensuring the resilience of these increasingly networked systems will require sustained investment in cybersecurity provisions and ongoing regulatory attention, particularly as grid modernization accelerates the pace of digital integration.

Conclusion

The central lesson from the LBNL analysis and broader evidence is that electricity price outcomes are not driven by demand growth alone but by how the system responds to it. Prices rise when new demand triggers high-cost infrastructure buildout, reflects inefficient planning, or shifts costs unevenly across customers. They can fall, or grow more slowly, when low-cost supply is available, existing infrastructure is more fully utilized, and cost allocation ensures that new demand contributes to system efficiency.

This framing points to a clear set of policy priorities across time horizons. In the near term, the most immediate opportunity is to optimize the existing system—deploying grid-enhancing technologies, demand response, and large-load flexibility to unlock latent capacity and defer costly new investment. In the medium term, structural reforms are needed: improving tariff design and cost allocation, and enabling new supply to be built and connected at lower cost via reforms to interconnection queues, transmission siting, and permitting for energy projects. Over the longer term, risk management becomes central, as

costs related to storm damage, wildfire mitigation, and cybersecurity increasingly shape the trajectory of retail prices.

The most adverse price outcomes are not inevitable. They are the result of policy and regulatory choices. Delivering affordable electricity depends on aligning supply, infrastructure, and cost allocation so that rising demand can drive higher utilization and lower costs—taking advantage of load growth as an opportunity, rather than a liability.

Notes

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Data Center Power Demands Are Contributing to Higher Energy Bills

By Miguel Yañez-Barnuevo (/authors/miguel-yanez) ✉ (mailto: myanez@eesi.org)

February 24, 2026

Key Takeaways:

- As data centers expand nationwide, utilities are receiving hundreds of gigawatts in interconnection requests, necessitating significant infrastructure investments.
- Natural gas power plants are being built and existing coal power plants are being propped up to meet the surging demand from data centers.
- Electricity bills are spiking for many households, contributing to an affordability crisis, particularly for the most vulnerable communities.

As data centers expand nationwide, utilities are receiving hundreds of gigawatts in interconnection requests, with implications for the power grid and consumers. Dozens of utilities received data center requests for at least 700 gigawatts (GW) of power connection development (<https://www.sierraclub.org/articles/2025/08/fools-gold-when-700-gigawatts-data-centers-come-knocking>) in 2025, which is more than the 477 GW (<https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php>) in electricity that the United States consumed in all of 2023. Even though many of these projects will never be built, the requests are still leading to a ramp-up in energy infrastructure investments, including generation facilities, transmission lines, and transformers.

Utilities make decisions about building or purchasing new power in a complicated ecosystem of independent system operators (ISOs), state energy regulators, and local regulations. Electric utilities are the first to receive load-interconnection applications (or applications to connect to the grid) for proposed data centers within their service territories. Regulated investor-owned utilities are obligated to serve interconnection requests within their service territory, as set out in the “obligation to serve” (https://www.eba-net.org/wp-content/uploads/2023/02/21_6EnergyLJ1791985.pdf) or “duty to serve” legal principle. All types of utilities—regulated and non-regulated—must balance these power requests against current generation capacity, future demand projections, and reliability concerns. State energy regulatory entities (i.e., public utility commissions) approve requests (<https://www.canarymedia.com/articles/guides-and-how-tos/power-by-people-glossary-bundle>) from regulated utilities to increase energy rates to cover upfront investments in building new power plants, transmission lines, and related infrastructure, such as transformers. Non-regulated utilities can adjust their rates without seeking approval.

An Affordability Crisis Is Brewing

To cover the investments needed to accommodate the surge in interconnection requests, many utilities are passing on the costs to their consumers through higher monthly utility bills. Utilities requested more than \$29 billion (<https://www.canarymedia.com/articles/utilities/why-power-bills-are-rising>) in rate increases in the first half of 2025, double the amount requested in the first half of 2024. Electric rate increases were expected to affect 40 million customers nationwide last year. This is in addition to the rate increases granted by state energy commissions over the previous couple of years.

Before 2019, electricity prices had been flat (<https://fred.stlouisfed.org/series/APU000072610>) at around 13 cents per kilowatt-hour (kWh) for more than a decade—in part thanks to energy efficiency policies that reduced energy consumption as the overall domestic economy grew. By the end of 2025, however, average electricity prices in the United States increased to 19 cents per kWh (<https://fred.stlouisfed.org/series/APU000072610>), about 27% more (<https://www.resources.org/archives/whats-happening-to-electricity-affordability-in-five-charts/#:~:text=Nationally%252C%2520average%2520real%2520electricity%2520prices,during%2520most%2520of%2520the%25202010s.>) than in 2019.

EESI Data Center Resources

See all of our articles on the impacts of data centers, including their energy needs, water usage, noise pollution, and contribution to higher energy bills:
The Environmental Impacts of Data Centers (Article Series)
(<https://www.eesi.org/data-center-impacts>)

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In states with a high concentration of data centers like Virginia, electricity prices have increased by up to 267% over the last five years (<https://www.bloomberg.com/graphics/2025-ai-data-centers-electricity-prices/>). Such spikes are due to utilities needing to quickly deploy infrastructure, such as power lines and transformers, and pay extra for market-rate energy.

Electricity prices are not expected to decrease anytime soon. According to the U.S. Energy Information Administration, residential electricity prices rose by 11.5% in 2025 (https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_5_03), outpacing inflation. Looking further ahead, prices are expected to increase by up to 40% by 2030 (https://www.icf.com/-/media/files/icf/reports/2025/energy-demand-report-icf-2025_report.pdf?rev=c87f111ab97f481a8fe3d3148a372f7f) compared to 2025.

The Cost of Reviving Coal

Some coal plant retirements are being delayed (<https://insideepa.com/climate-extra-share/253179>) to meet the increased demand from data centers, often at the behest of the Trump Administration. But these delays can be costly because most facilities were built in the 1970s and 1980s and have reached the end of their typical 40-year lifespan. Refurbishing a coal power plant to extend its lifespan past the typical 40 years can cost up to \$1.3 billion (<https://ieefa.org/articles/prolonging-retirement-age-coal-generators-puts-affordable-power-supply->

Data Centers and Fossil Fuels

This article is part of a series, The Environmental Impacts of Data Centers (<https://www.eesi.org/data-center-impacts>). A previous article (<https://www.eesi.org/articles/view/data-center-buildout-is-hungry-for-fossil-fuels>) in this series discussed how utilities are responding to increased energy demand from data centers by building new natural gas power plants and reviving old coal plants, leading to higher carbon emissions and health impacts on nearby communities.

risk#:~:text=%25E2%2580%259CFurther%252C%2520extending%2520the%2520life%2520of,20%2525%2520even%2520after%2520the%2520upgrades.). Moreover, the cost of operating these plants increased by 28% (<https://energyinnovation.org/wp-content/uploads/Coal-Cost-Update.pdf>) from 2021 to 2024 due to higher fuel, capital (including debt service), and maintenance costs. These higher costs are passed on to consumers. In addition to being expensive to run, coal plants also have negative health and environmental (<https://www.epa.gov/power-sector/human-health-environmental-impacts-electric-power-sector>) impacts, especially on local communities.

Gridlock on the Natural Gas Buildout

Utilities faced with higher electricity demand are also looking into building new natural gas plants. But because so many utilities are exploring new plants at once, the average time to construct a new plant has increased from four and a half years to at least six (<https://www.utilitydive.com/news/nextera-energy-ceo-urges-energy-pragmatism-amid-rising-costs-demand/746207/>), and wait times for gas-fired turbines can reach up to seven years (<https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply>). As a consequence, currently-proposed natural gas power plants will not enter service until at least 2030.

These delays are creating ripple effects (<https://gridlab.org/portfolio-item/gas-turbine-cost-report/>) across the energy supply chain and the labor market. The scarcity of transformers and iron and steel pipes is slowing down the already lengthy permitting and construction process, thereby further increasing costs. Labor costs (<https://gridlab.org/portfolio-item/gas-turbine-cost-report/>) are also rising due to a tight labor market in construction.

All of these factors add up: the cost to build a new plant has tripled since 2022 (<https://gasoutlook.com/analysis/costs-to-build-gas-plants-triple-says-ceo-of-nextera-energy/#:~:text=%25E2%2580%259CWe%2520built%2520our%2520last%2520gas%252Dfired%2520facility%2520in%25202022%252C%2520at%2520%2>). Natural gas plants expected to enter service in 2030 or later are reporting costs of \$2,000 (<https://gridlab.org/portfolio-item/gas-turbine-cost-report/>) per kW, which may soon rise to \$3,000 (<https://gasoutlook.com/analysis/costs-to-build-gas-plants-triple-says-ceo-of-nextera-energy/>). These higher generation costs are passed on to consumers through higher monthly energy bills.

Disadvantaged Communities Are Footing the Bill

Higher energy bills disproportionately affect disadvantaged communities, which often face significant energy burdens (<https://www.aceee.org/energy-burden>). Low-income residents, renters, Black households, and Hispanic households spend up to 20% of their income (https://www.aceee.org/sites/default/files/pdfs/data_update_-_city_energy_burdens_0.pdf) on energy, compared to 3% for higher-income households. Even before the data center boom, one in four households (<https://www.eia.gov/todayinenergy/detail.php?id=51979>) reported having difficulty paying their energy bills or maintaining safe indoor temperatures because of energy costs.

Soaring energy bills exacerbate insecurity for low-income households and renters. Utility bills go unpaid as families struggle to afford other essentials, such as food or medicine, leading to disconnections. About 21 million households (<https://neada.org/wp-content/uploads/2025/08/costofpower.pdf#:~:text=utility%2520bills.,falling%2520deeper%2520into%2520financial%2520distress.&text=The%2520Census%—one%20in%20six%20in%20the%20United%20States—are%20behind%20on%20their%20utility%20bills.>) are behind on their utility bills. Total outstanding utility bill debt for U.S. households reached \$25 billion in June 2025, an

increase from about \$15 billion in early 2022 (<https://neada.org/wp-content/uploads/2025/08/costofpower.pdf#:~:text=utility%2520bills,falling%2520deeper%2520into%2520financial%2520distress.&text=The%2520Census%2520As%2520a%2520result,utility%2520shut-offs%2520skyrocketed%2520to%25203.5%2520million%2520in%25202024%2520and%2520may%2520have%2520reached%25204%2520million%2520in%25202025,putting%2520further%2520strain%2520on%2520disadvantaged%2520households.>)

To protect residential and small-business consumers from higher energy charges, utilities and state regulatory agencies (<https://www.utilitydive.com/news/kansas-michigan-data-center-large-load-evergy-consumers/805115/#:~:text=from%2520your%2520inbox,.,Kansas%2520C%2520Michigan%2520regulators%2520approve%2520large%2520load%2520rules>) the country are starting to create separate, specialized rate classes and retail tariffs for large-load uses (<https://affordability-toolkit.rmi.org/policies/tariffs-for-large-load-customers>), including data centers. In the meantime, energy efficiency (<https://www.energystar.gov/about/how-energy-star-protects-environment/energy-efficiency>) measures can help families shield themselves from rising energy costs while utilities and regulators determine how to meet increased energy demand without penalizing residential customers. On-bill financing (<https://www.eesi.org/obf/main>) is one innovative solution that helps households access energy efficiency upgrades at lower cost, especially in rural areas served by member-owned electric cooperatives.

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