Rhodium Group

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Caught in the Current: Historical and Prospective Drivers of Changes in US Electricity Prices

Energy & Climate

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Executive Summary

The US has clearly entered a new period of rising electricity prices compared to recent history. However, recent price increases are not driven by a single specific factor but rather by multiple, intersecting factors that vary substantially regionally and by individual utility. A confluence of increasing volatility in natural gas prices that provide an increasing amount of generation, rising distribution and transmission system expenditures, inflation, storm recovery and wildfire mitigation, and shifting policy factors have all contributed to recent price increases.

Significant load growth from data centers generates substantial attention, but understanding its impact on electricity prices requires care. Nationally, load growth is correlated with lower prices as existing assets are used more effectively. However, the sudden and transformative amounts of proposed data center builds may change that relationship. Indirectly, proposed data center builds are already responsible for price increases in the PJM electricity market region and for contributing to a supply chain crunch of key grid equipment. As utilities and grid planners make major infrastructure investment decisions, pressure on prices may grow.

Our assessment of drivers shows no major price decrease drivers in the near future, given fuel price volatility, continued inflationary pressures, supply chain and infrastructure constraints, and new investment needs that are on the table (Figure ES-1). Recent geopolitical events like the war in Iran have added further uncertainty to how prices could evolve over the rest of this decade. There is no quick fix on the table for policymakers to adopt—a comprehensive and long-term suite of solutions is needed.

FIGURE ES-1

Key drivers of electricity price change

Scale of impact: Minimal , Moderate , Major

Driver	2010-2020	2021-2025	2026-2030
Natural gas prices	Low prices from expansion of hydraulic fracturing	Volatile prices from extreme weather and increasing LNG exports	LNG exports expanding, increasing exposure to international prices and geopolitical events
Transmission and distribution infrastructure	Modest investment trends, through beginnings of current distribution cost growth in the mid-2010s	Significantly increased distribution expenditures	Load growth, system resilience needs, and overall replacement of aging assets likely to keep expenditures high

Inflation	Low, 2% or less	Inflation shock post-pandemic, key grid equipment prices remain elevated	Unknown, but could rise again if Iran war leads to sustained high oil prices and supply chain disruption
Extreme weather and wildfire	Constant but not accelerating impact on rates. Wildfire liabilities were low.	Increasing frequency and severity of storms, increasing wildfire costs in California	Mitigation and adaptation costs likely to continue at current pace
Load growth	Minimal	Increasing in pockets, but not a major national driver to date outside PJM region	Likely to be high, which may drive cost increases absent policy intervention or major market redesigns
Utility profits	Relatively stable utility return on equity (RoE), though likely elevated relative to true cost of equity	Relatively stable RoE, increasing slightly with interest rates	Difficult to envision RoE rising in current political environment, but current RoE could drive additional capital expenditures
State clean energy policies	Low compliance costs to date in most states; isolated increases from rooftop solar adoption	Select regions with binding targets and low resources; continued growth of rooftop solar in select states	Potential cost pressure in high-adoption states from net-metered solar absent reforms; increasing 2030 clean energy targets and constrained supply
Federal policy actions	Generally consistent renewable tax policies	Expansion of tax credits and federal funds for power infrastructure	Expiration of tax credits will begin to bite; tariff uncertainty; other renewable restrictions and forced coal retirement delays

CHAPTER 1

Unpacking Key Drivers of Electricity Price Change

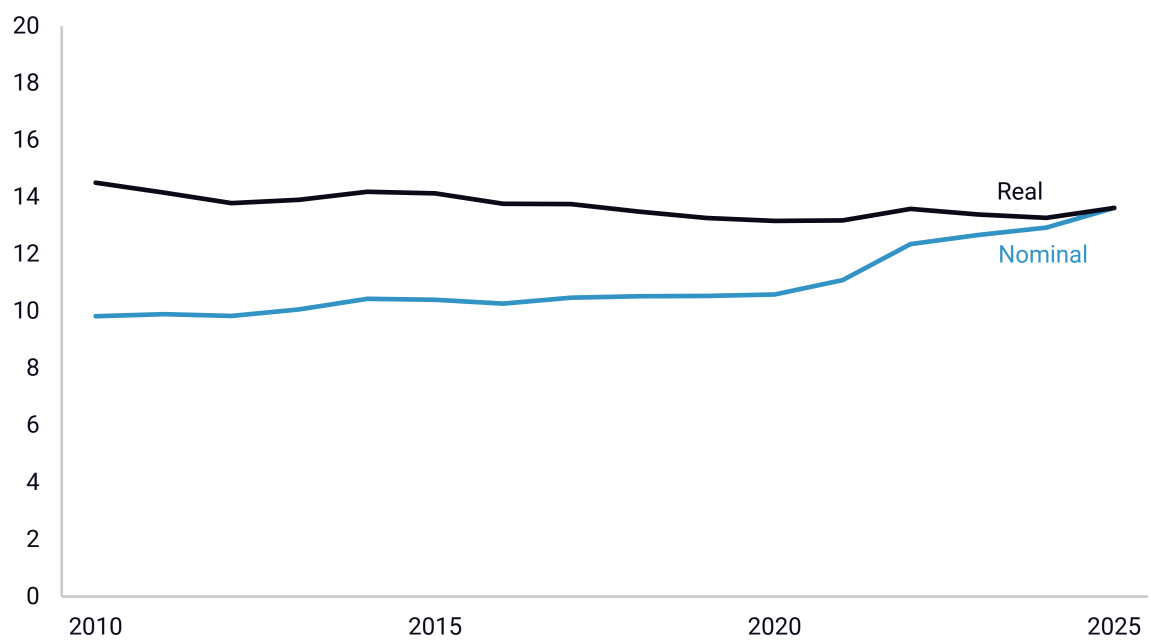
Increasing electricity prices are a relatively new phenomenon in this era of the US grid. In real terms, electricity prices saw sustained growth for nearly all of 1974 to 1983, reaching an increase of more than 40% over that window, and similarly sustained growth of 14% from 2004 through 2009. But these periods of continuous price increases outrunning inflation are the exceptions, not the rule, looking back at electricity prices since 1960.

Since 2010, the US has been in another long period of largely uneventful national average electricity prices, rising slowly over the decade and even falling modestly after adjusting for inflation (Figure 1). As a result, real average electricity prices actually decreased by 9% from 2010 through 2020. This decrease was far from universal, as we'll unpack later, and several regions of the country experienced meaningful growth, but on the whole, prices were mostly stable.

FIGURE 1

Average economy-wide US electricity prices

Nominal and real (2025 USD) cents per kilowatt-hour (unless otherwise noted)



Source: Rhodium Group, EIA

Relatively flat national average electricity prices were a function of an era with several macroeconomic factors keeping prices low:

- **Relatively low natural gas prices** due to the increasing domestic supply from wider use of hydraulic fracturing. Natural gas prices for the power sector were on average 44% lower from 2011 to 2020 compared to the prior decade, with natural gas increasing from 25% to over 40% of the generation mix over the same period.

- **Retirements of aging and less efficient coal units** through a combination of increasing environmental regulations on hazardous air emissions and coal ash ponds and subsequent replacement with more efficient and lower cost natural gas units. 99 GW of coal plants (32% of the total coal fleet) retired from 2010 to 2020.
- **Falling costs and increasing deployment of wind and solar** resources due to technology advancement, federal tax incentives, and state clean energy policies. Wind and solar levelized costs fell 63% to 77% in real terms from 2010 to 2020, respectively.
- **Flat demand growth** due in part to growth in efficiency technologies like LED lighting, limiting the pace and need for new infrastructure investment. Total electricity sales were essentially flat from 2010 through 2020 while annual GDP grew 42%.
- **Low interest rates** with 10-year US Treasury securities interest rates averaging 2.3% over the period, keeping borrowing costs low for capital-intensive electricity generating units and other power sector infrastructure.

Drivers keeping electricity prices low have waned

However, since 2021, many of these drivers are either no longer present or are actively changing to become drivers for price increases. The expansion of liquified natural gas (LNG) exports and armed conflicts mean domestic low-cost natural gas is not a sure thing. Explosive load growth from data centers is necessitating major grid investments. Wind and solar costs have stopped falling and are facing cost increases due to supply chain issues, accelerated expiration of federal tax credits, and rising interest rates.

Electricity prices have been rising more sharply in this period, rising even faster than inflation in 2022 and in 2025, with national average electricity prices increasing almost 29% in nominal terms since 2019 after having risen only 8% from 2010 to 2020. Residential customers are seeing price increases more acutely, with a 33% increase over that same time. Customers are raising concerns about increasing electricity bills, catching the attention of national news media in a series of articles, vaulting the affordability issue to the top concern for governor races in Virginia and New Jersey, and even getting national attention for the usually uneventful elections for state utility regulators in Georgia.

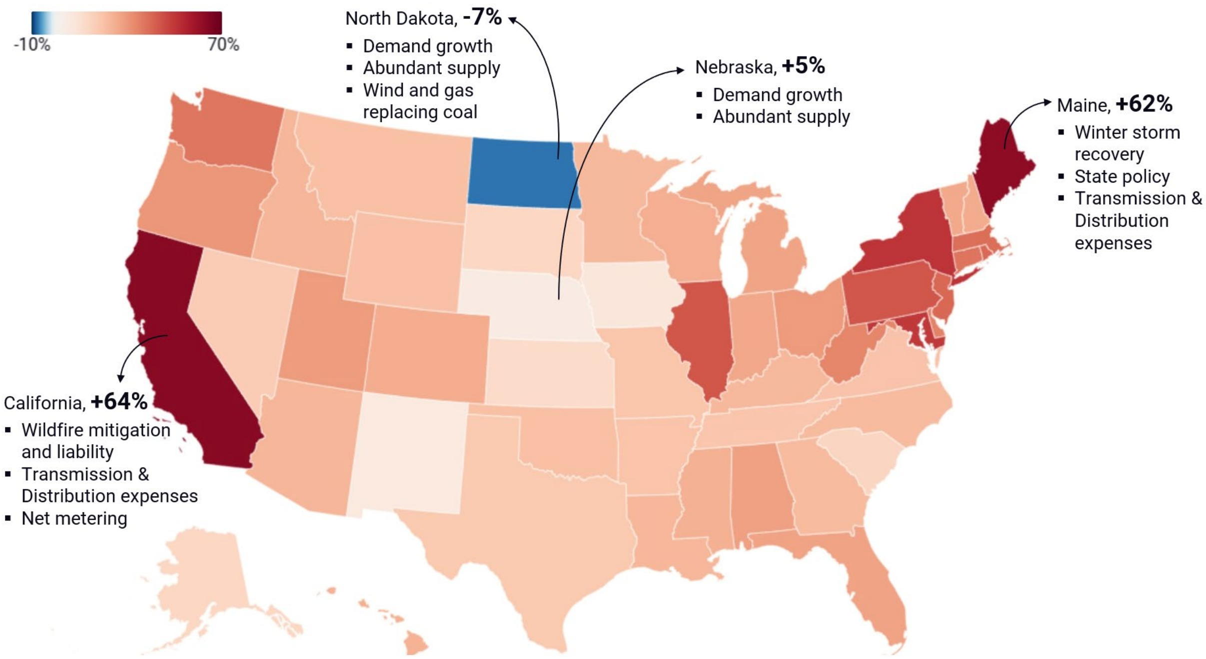
Price increases vary regionally and reflect a diversity of drivers

Reviewing the state-level change in electricity prices from 2019 through 2024 demonstrates that increases are not uniform across the nation, also reflecting the fact that there is no single underlying issue driving electricity price increases to date (Figure 2).

FIGURE 2

Change in average retail price, 2019-2025

Percent change in nominal retail price



Source: Rhodium Group, EIA

California stands out among all states with a massive 64% increase in rates since 2019 (30% after adjusting for inflation), driven by significant and unique wildfire-related expenses accounting for 40% of the rate increase at least through 2024. Other significant drivers include transmission and distribution investments and growth in net-metered solar power. New England states plus New York have seen significant increases due in part to storm recovery, exposure to higher natural gas prices, and compliance costs for meeting renewable portfolio standards. Broader increases in the Mid-Atlantic states and a few Midwest states reflect both increasing gas prices and capacity prices in regional wholesale markets.

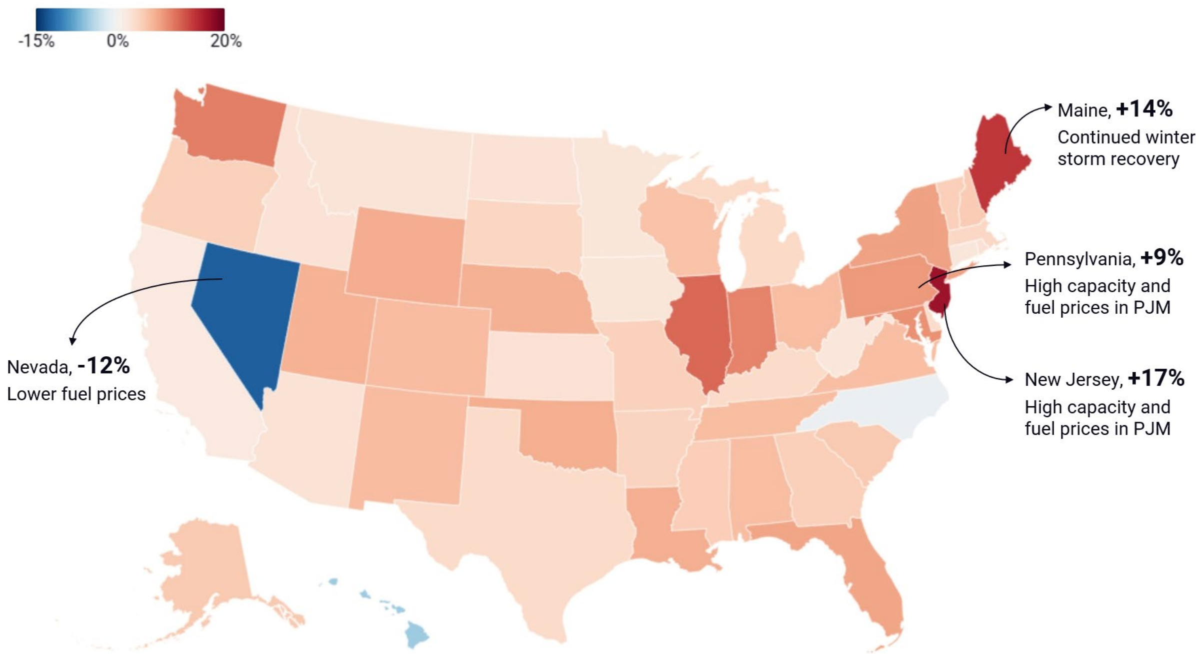
Counter to national trends, a few states have experienced price decreases over this same period. North Dakota experienced the largest electricity price decrease since 2019, falling 7% in nominal prices and 1% after accounting for inflation. This reflects a few unique factors: the state saw growing demand from oil and gas operations along with other commercial and industrial customers. Coupled with low-cost and abundant natural gas and renewable electricity generating resources and the retirement of some older and more expensive coal units, this enabled utilities to better use existing infrastructure and spread fixed costs over more sales, keeping prices low.

More recently, year-over-year changes in electricity prices continue to be diverse and significant in certain regions, reflecting the volatility and idiosyncrasy of drivers in individual states (Figure 3).

FIGURE 3

Change in residential retail electricity price, 2024-2025

Percent change in nominal retail price



Source: Rhodium Group, EIA

Key factors affecting electricity retail prices in 2025 include:

- **High capacity prices in PJM began to be reflected in new supply contracts in June 2025**, driving price increases in Mid-Atlantic states like Pennsylvania, New Jersey, and Maryland, and into parts of the Midwest like Ohio and Illinois.
- **Maine continues to see price increases from severe storm recovery,** with customers paying about $20 per month to address recovery from winter storms in 2024. One of the major utilities in the state had a rate increase take effect in July 2025, citing storm recovery costs as the primary driver, with secondary drivers from costs associated with net energy billed solar and other clean energy contracts.
- **Indiana utilities are investing in new generation and grid upgrades.** For example, NIPSCO implemented a rate increase in July 2025, citing a $2 billion investment in new generation assets along with $770 million in other critical infrastructure replacements to improve reliability.
- **Nevada experienced a decrease from lower fuel prices.** A portion of the bill for NV Energy is automatically adjusted quarterly, and reflected lower costs of fuel and purchased power in 2025 relative to 2024, mostly due to lower natural gas prices.

While the individual factors and their magnitude may vary from state to state, there are clear underlying regional and national drivers influencing electricity prices.

Where will electricity prices go?

Does this represent a transition to a new era of increasing electricity prices driven by explosive but still mostly speculative data center demand, or a short-term disruption as the industry manages the long-tailed fallout from pandemic-era supply chain disruptions? Absent significant and coordinated policy action, the diversity of factors pointing to price increases means that electricity prices likely will continue their significant upward trajectory over the next five years.

In the next chapter, we take a deeper dive into the key factors that have (and have not) had major impacts on recent electricity price trends: natural gas price and volatility, transmission and distribution system investments and their drivers, load growth, utility return on equity, and state and federal policy changes. We also look for indicators about the extent to which those impacts may persist. In the last chapter of this report, we take a more holistic look at future price drivers and provide some preliminary examples of ways policymakers are responding.

CHAPTER 2

A Deeper Dive into Key Drivers

Each region and individual utility has its own set of diverse and characteristic reasons for cost changes over time. However, there are a few clear major drivers and trends that broadly and collectively influence high electricity prices. Here we unpack these trends, how they intersect, and offer a glimpse of where they may go in the future.

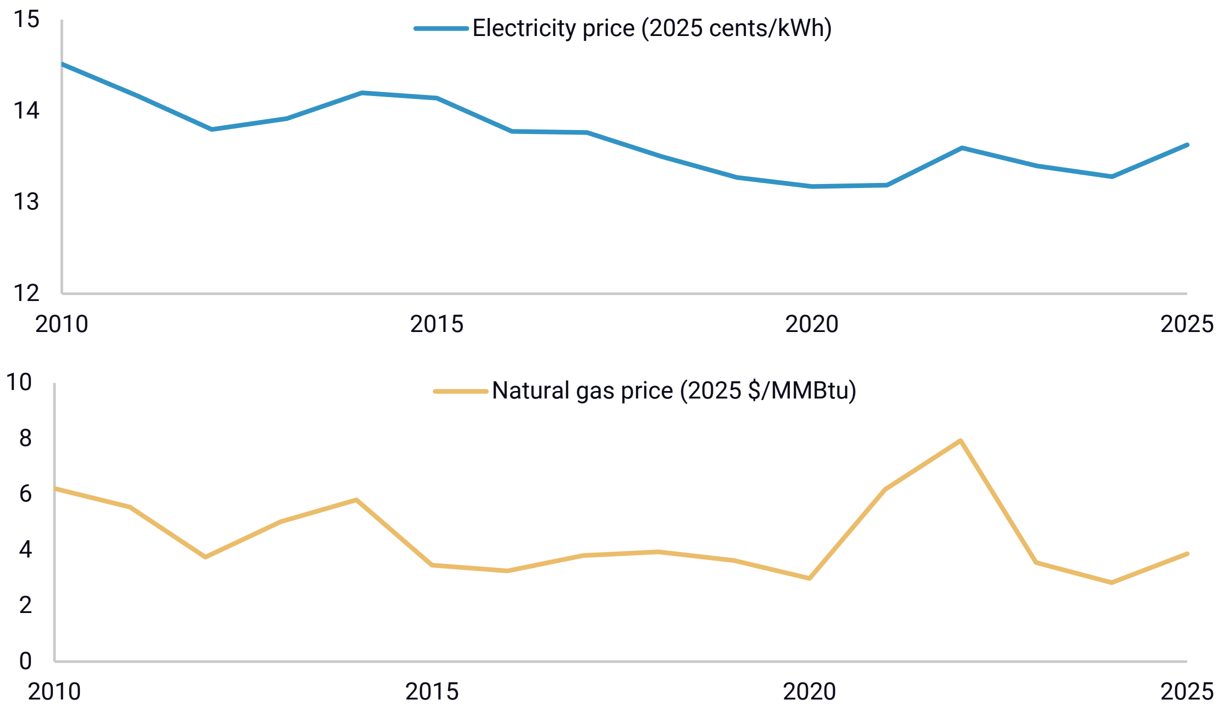
The era of consistently low-cost natural gas may be shifting

Natural gas prices are a major determinant of changes in electricity prices. The power sector has benefited from the expansion of domestic natural gas production, with natural gas increasing from 24% of total electricity in 2010 to over 40% by 2020. This trend shows little sign of abating in the near term: we project natural gas generation to at least stay flat and, in some cases, increase by as much as 12% in 2030 relative to 2024 levels in Taking Stock 2025. Given its widespread use, natural gas fuel prices are a key determinant of retail electricity prices. Especially in regions with organized electricity markets, natural gas generators are typically on the margin, meaning their costs set the overall wholesale price of electricity. As a result, electricity and natural gas prices are often quite in sync (Figure 4).

FIGURE 4

National average electricity price and power sector natural gas fuel price

2025 cents/kWh (electricity); 2025$/MMBtu (gas)



Source: Rhodium Group, EIA

However, increasing demand for natural gas from LNG exports and volatility in gas prices due to winter weather storms are changing the paradigm of low-cost gas and associated low-cost electricity. Statistical analysis of individual states' exposure to natural gas generation shows that natural gas prices have been among the largest factors impacting year-to-year changes in electricity prices. Some locations, most notably states in the Northeast, face natural gas pipeline constraints and higher prices, primarily in the winter when the gas network is also being used for building heating. During certain times, New England states are served by LNG imports, directly exposing customers in those regions to higher LNG prices.

This volatility drives changes in electricity prices. The period of summer 2021 through summer 2022 saw a doubling of natural gas prices driven by a confluence of factors: recovery of industrial demand as the economy emerged from COVID-19 related impacts, colder than average winter temperatures depleting storage, increasing demand from LNG exports, and the sudden surge in demand from Europe after the disruption of supply from Russia due to the Russian invasion of Ukraine in early 2022. The surge in natural gas prices directly led to the largest single-year increase in electricity prices: national average prices increased 10% in 2022 as compared to 2021.

The increasingly interconnected nature of LNG exports and impact on domestic prices was illustrated by an unexpected disruption in export capacity. A fire at the Freeport LNG export terminal in Texas led to a full shutdown of the facility on June 8, 2022 for an extended period, representing a loss of 17% of the total US export capacity at the time. The supply that was intended for export now instead became available to the domestic market, and decreased gas prices by 40% through July 4.

Several winter storm events have caused short-term disruptions to gas supplies, with associated price spikes that can have long-lasting impacts for consumers. A series of winter storms in recent years, including Uri in 2021, Elliot in 2022, Heather in 2024, and Fern in 2026, have highlighted how supply disruptions during periods of high demand for both heating and electricity generation can lead to extreme price spikes. Utilities end up spending significant amounts of money on fuel purchases to keep plants operational during these events, but customers ultimately pay. Regulators often approve special cost-recovery mechanisms, spreading the recovery over multiple years to ease the shock on customers but keeping bills elevated for longer. For example, the largest electric utility in Oklahoma sought approval to spread cost recovery of fuel and power purchases over a 10-year period after spending over $1 billion during winter storm Uri in 2021.

ELECTRICITY PRICE EXPOSURE TO NATURAL GAS VOLATILITY REMAINS A KEY AFFORDABILITY RISK

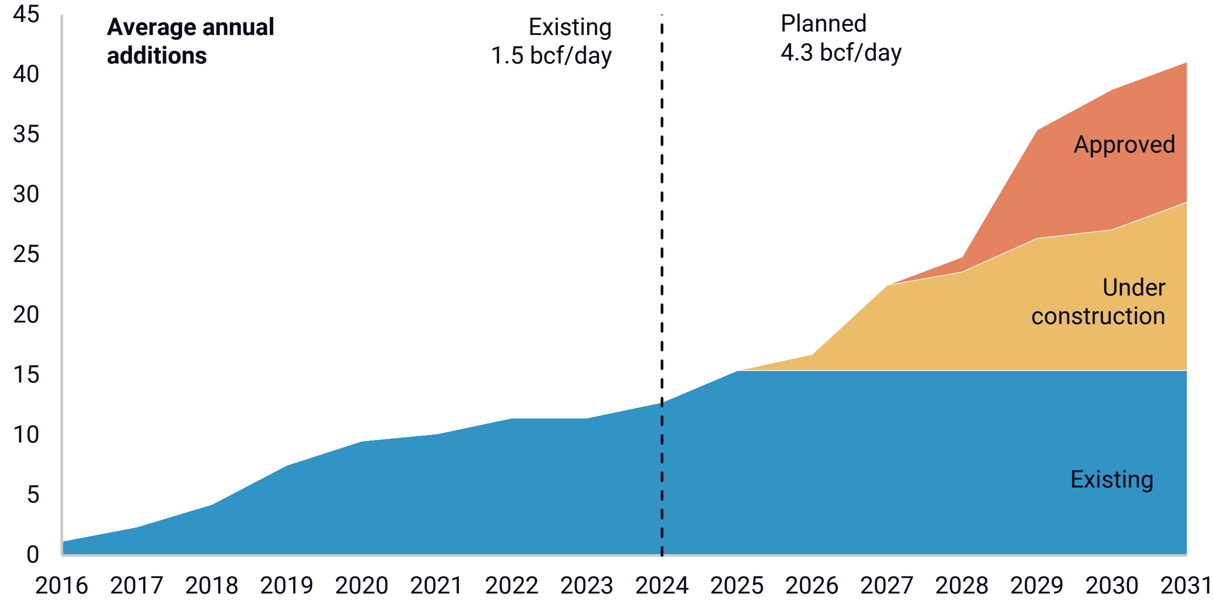
Looking ahead, most factors are poised to continue upward price pressure on natural gas, impacting electricity prices, even as domestic production continues. EIA expects natural gas production to remain at record high levels, but still anticipates increasing gas prices in 2026 and 2027 on average, even before accounting for possible impacts due to fallout from disruption in supply from the Persian Gulf due to the ongoing conflict in Iran.

LNG exports will continue to increase. Export capacity has increased by an average of 1.7 billion cubic feet per day (Bcf/d) each year since 2016, when the first export terminal came online (Figure 5). Based on projects under construction and those with approved permits, this pace of expansion will accelerate, with additions averaging 4.3 Bcf/d through 2031. This will continue to both increase demand for natural gas and expose the domestic gas market to international LNG prices. An increase in LNG export capacity roughly aligned with the addition of the "approved" capacity in Figure 5 leads to as much as a 22% increase in wholesale domestic natural gas prices by 2035.

FIGURE 5

Historical and planned liquefied natural gas export capacity

Cumulative billion cubic feet (bcf) per day



Source: Rhodium Group, EIA

International demand for LNG is likely to grow in the near future. Many Asian economies are reliant on LNG imports and have built out infrastructure with an expectation of a secure supply of LNG, and overall pay significantly higher prices than domestic US gas customers. The war in Iran has disrupted gas supplies out of Qatar, and it is unknown how long it will take to resume shipments even if hostilities end quickly due to possible damage to export infrastructure. Other countries dependent on LNG supplies will find it difficult to change course in the short term. As such, LNG export growth could even exceed currently approved projects despite the record-breaking size of the current expansion.

Explosive data center growth will add to domestic natural gas demand. In addition to the demand by utilities seeking to meet load growth primarily for data centers, developers of data centers are increasingly looking to natural gas to provide significant amounts of on-site power. One assessment of announced projects identified over 23 GW of gas turbines or engines to be used for on-site data center power generation. The impact of data center growth overall is further explored below.

Extreme winter weather is increasingly disrupting supply. As noted above, even short-term disruptions and price spikes can lead to long-lasting impacts for electricity customers. With worsening effects of climate change increasing the severity and frequency of storms, we can expect further disruptions and volatility in gas pricing.

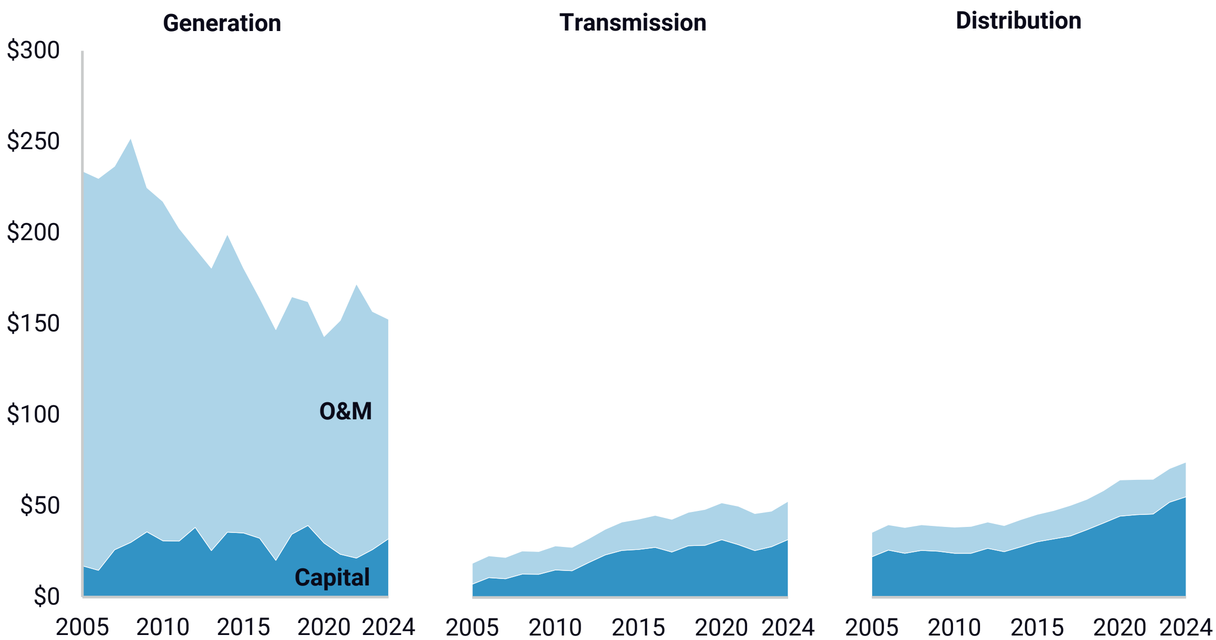
Power delivery infrastructure expenditures increasing due to grid expansion, inflation, and extreme weather

Growing spending on grid infrastructure—primarily the distribution system, including lower voltage substations and wires that deliver electricity to homes and businesses—is a major driver of electricity price increases. Investor-owned utilities' capital investments in distribution systems have increased 35% since 2019, rising by over $14 billion in annual expenditures (Figure 7). Transmission investments in certain regions are also beginning to be reflected in higher electricity prices. This stands in stark contrast to generation expenditures, which fell significantly since 2010, reflecting lower-cost natural gas discussed above, along with increasing amounts of wind and solar deployment (Figure 6).

FIGURE 6

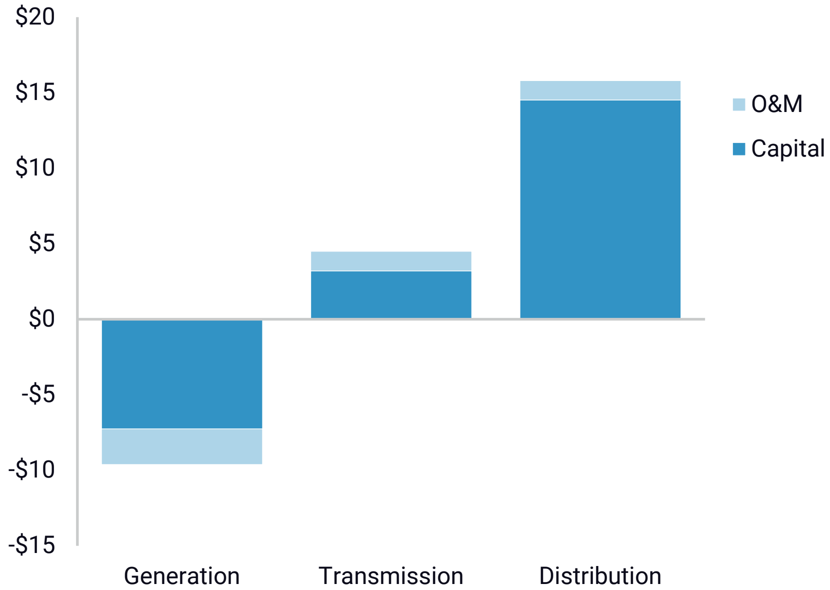
Annual electric investor-owned utility expenditures

Billion 2024 USD



Source: LBNL, FERC Form 1, Rhodium Group

FIGURE 7
Change in investor-owned utility expenditures by category, 2019-2024
Billion 2024 USD



Source: LBNL, FERC Form 1, Rhodium Group

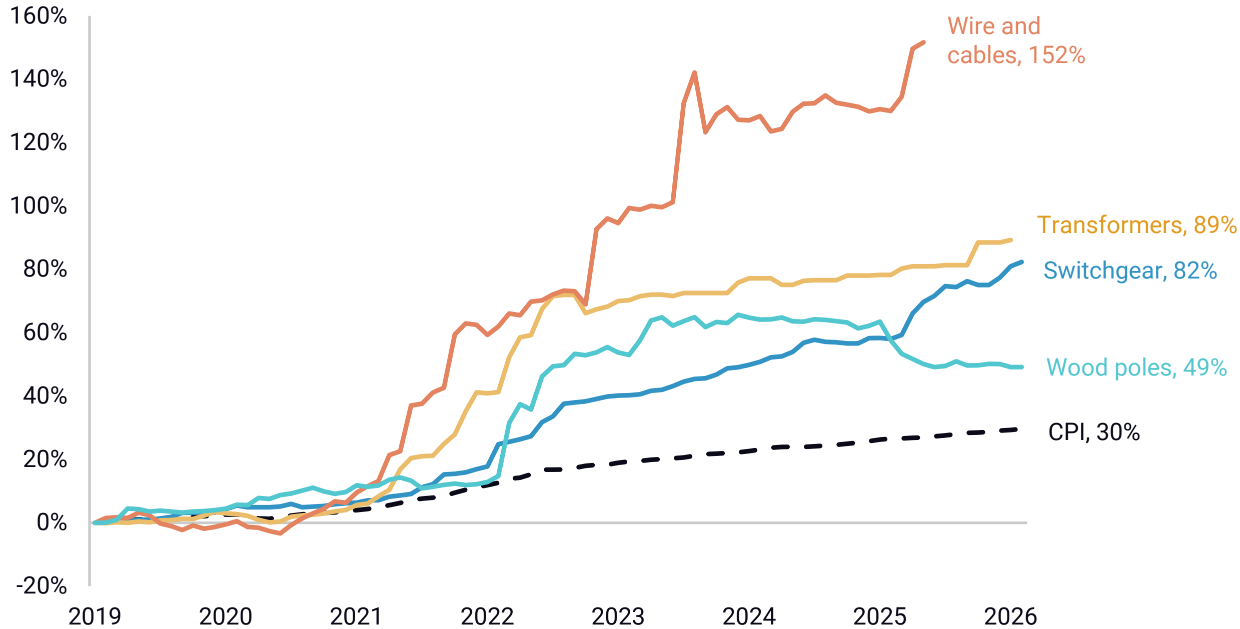
Utilities are modernizing distribution systems, replacing aging infrastructure, and preparing for growth. Expenditures in distribution systems encompass a wide range of purposes and equipment. Accelerating expenditures in recent years—especially for new poles, undergrounding lines, and transformers—partially reflect the need to replace and upgrade aging grid assets, partially to modernize systems, and partially to improve resilience against increasing threats to reliability from extreme weather and other disasters.

In addition, key equipment has increased in price far faster than inflation. Increased distribution system expenditures also reflect the fact that the cost of key equipment has increased far faster than the overall rate of inflation. Wire and cable, transformers, switchgear, and wood poles have increased 50-152% in cost since 2019, compared to a 29% increase in the overall CPI over that time (Figure 8). Combined with overall inflation for items like labor and construction costs, utilities are facing significant inflationary cost pressures. For some utilities with base rate updates occurring only once every three to four years, the accumulated impact of inflation hitting rates at once can shock consumers.

FIGURE 8

Producer price index for power sector equipment

Percent change relative to 2019



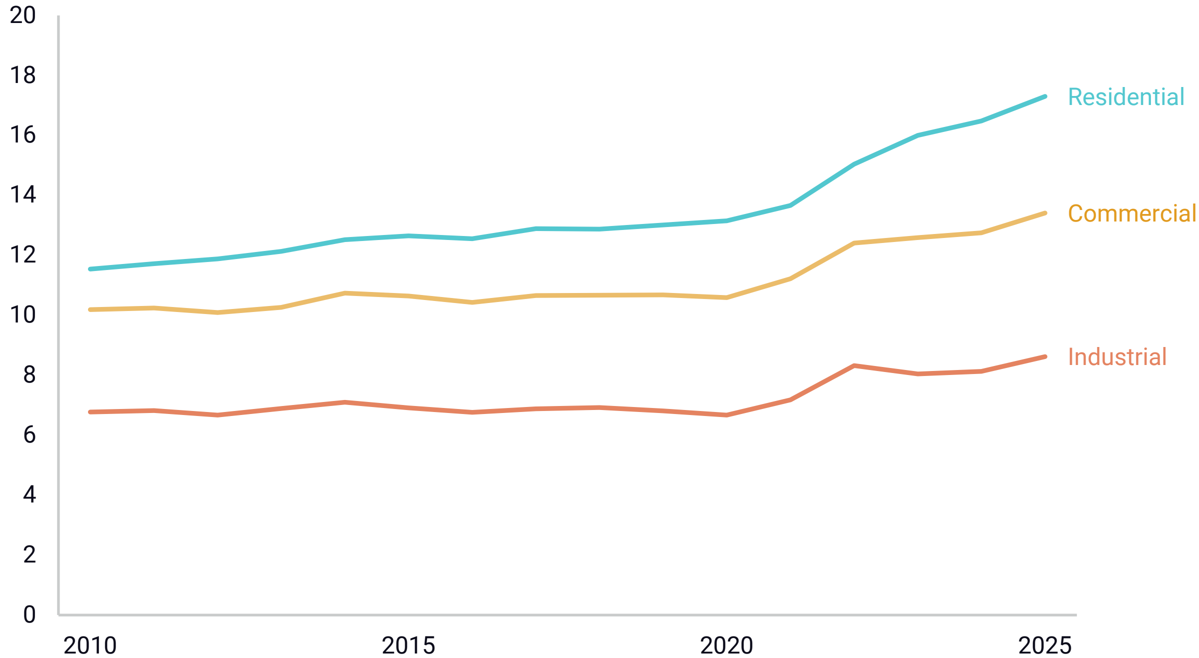
Source: BLS, FRED

Changes in distribution system expenditures also have an outsized impact on residential customers as compared to commercial and industrial customers. Utilities generally assign costs to customers that cause the cost, known as the cost causation principle. Therefore, the cost of maintaining and investing in the lower voltage distribution system, which primarily serves the large number of customers each using a small amount of electricity, falls primarily on residential and small commercial customers. Industrial and large commercial customers, which can connect more directly to a utility's higher voltage system and bypass the distribution system, do not bear as much of the distribution system cost. This partially explains the difference in average rates observed between customer classes, with industrial customers usually paying the lowest rates (Figure 9). Sometimes, industrial customers also receive a lower rate to incentivize economic development in a specific region.

FIGURE 9

Average national US electricity prices by sector

Nominal cents per kilowatt-hour



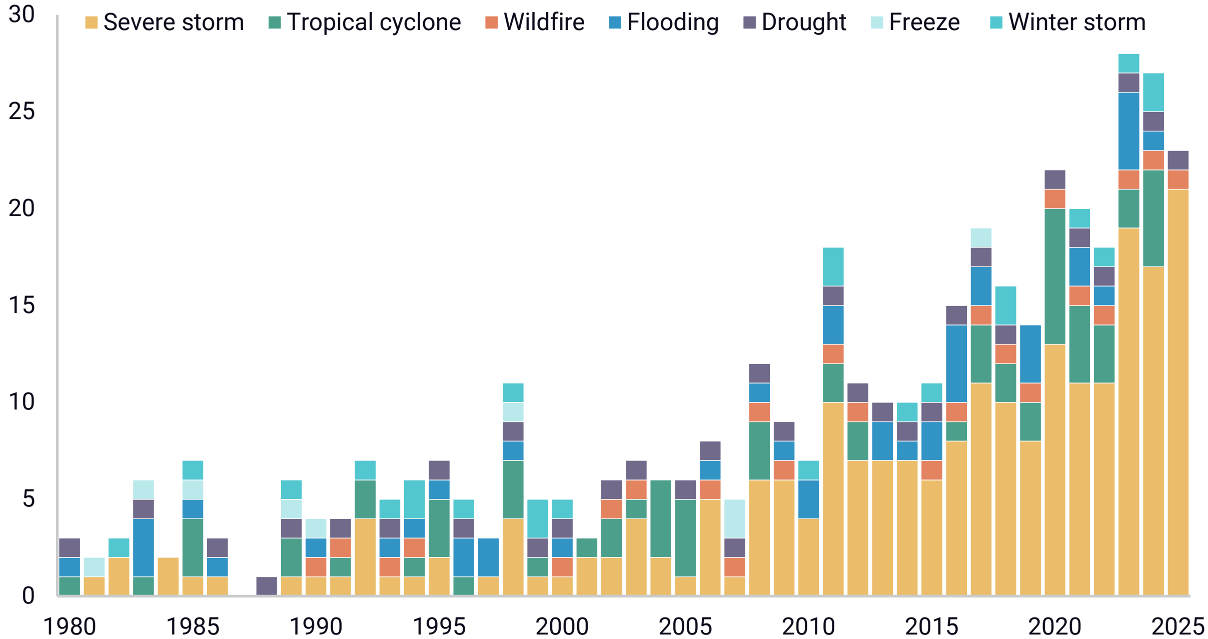
Source: Rhodium Group, EIA

Transmission expenditures are also a driver of rate increases in certain regions, though these impacts are more muted nationally (Figure 7). New England, California, and the PJM market regions have all experienced significant increases in transmission expenditures, accounting for an estimated 0.4 to 0.8 cents per kWh of inflation-adjusted price increases in those regions since 2019. Transmission investments overall *can* lead to lower cost systems, provided they are primarily used to access lower cost generation or otherwise relieve congestion on the system. However, if transmission investments are primarily for local reliability issues, replacements of aging assets, or for hardening against storm and wildfire risks—as it has been for New England and California in particular—then increased transmission spending acts as a cost driver.

EXTREME WEATHER RECOVERY AND MITIGATION DRIVE COSTS, ESPECIALLY IN THE EAST

The increasing risk of power equipment igniting wildfires and the associated liability that utilities may bear are driving significant investments to prevent future wildfires. This can involve significant capital investments in underground transmission lines in high-risk areas to increased operational spending on vegetation management and clearing.

FIGURE 10
Billion-dollar disasters
Count of billion-dollar disasters per year



Source: Rhodium Group, Climate Central

The increasing severity and frequency of extreme weather events driven by climate change are impacting electricity rates, as utilities invest in mitigation and hardening measures to prevent outages and need to recover costs from repairing damage caused by such storms. Severe storms and hurricanes causing at least $1 billion in damages (across all sectors, not just power) are increasing, with eight such events per year on average for 2011-2015, and more than doubling to 18 per year on average for 2021-2025 (Figure 10).

Because specific extreme weather events are unpredictable, utilities seek cost recovery after the fact, sometimes in the form of specific riders added to normal rates. Some storms necessitate almost complete rebuilds of a system's distribution system due to extensive damage exceeding annual O&M budgets, oftentimes dramatically so. Some recent examples include:

- Duke Energy Florida spent an estimated $1.1 billion to recover from a series of hurricanes in 2024 and added a one-year surcharge equivalent to $31 per month for the average residential customer.
- Central Maine Power (CMP) experienced a series of storms from 2020 through 2024, with storm expenditures in 2022 alone approaching $120 million. Overall storm recovery costs accounted for an estimated 2.5 cents per kWh of average electricity prices for CMP in 2025. CMP is now seeking approval for a multi-year rate case to invest in system hardening.
- Entergy Louisiana received approval to recover $3.2 billion in storm recovery expenditures for major storms and hurricanes in 2022 and 2021. Recovery will take

place over a 15-year period and is estimated to impact retail prices by 1.2 cents per kWh.

In response to these trends, utilities are also investing more in storm resilience measures, items like proactive planning, system hardening, undergrounding lines, expanded tree trimming and vegetation management, and weatherizing equipment to freezing temperatures and floods. These proactive expenditures increase the resilience of infrastructure and decrease the cost of future storms, but still require upfront capital spending that puts upward pressure on rates. Either utilities pay more predictable and controllable costs now to prevent future cost increases or pay more unpredictable and uncontrolled costs later, increasingly when, not if, extreme weather damages significant portions of their system.

WILDFIRE MITIGATION EXPENDITURES ARE INCREASING, ESPECIALLY FOR CALIFORNIA AND THE REST OF THE WEST

After the 2018 Camp Fire, sparked by PG&E equipment, led to the deadliest and most destructive fire in California history, California utilities have been spending significantly on both wildfire mitigation measures (e.g., undergrounding key transmission lines) and wildfire liability insurance coverage. In sum, spending on wildfire mitigation and insurance by the three large California investor-owned utilities totaled $16 billion and $11 billion, respectively, from 2019 through 2023, which ultimately was allowed to be recovered in retail electricity rates. This is estimated to account for 3.3 to 5.0 cents per kWh of retail electricity rates as of 2025.

Other high-profile deadly and damaging wildfires associated with electrical equipment in recent years (e.g., HECO and Maui wildfire in 2023, Xcel Energy and Marshall Fire in 2021) have led regulators and legislatures to begin mandating wildfire mitigation plans and associated expenditures. Twelve western states now have legislation requiring or supporting wildfire mitigation plans from utilities, up from only two in 2019.

UTILITIES ARE LIKELY TO CONTINUE TO SPEND ON INFRASTRUCTURE OVER THE NEAR TERM

The grid is aging, and many assets are reaching (or exceeding) their expected end of life. Some utilities are proactively investing to support new functions like electric vehicle charging and heating electrification. Inflationary pressures on equipment do not seem to be decreasing—at best, they are flat, but if broader economic effects from the war in Iran persist, then high oil prices and disrupted supply chains could drive another round of inflation on key grid components. Storm and wildfire investments are beginning to accelerate, and we expect to see those continue to impact bills over the next few years.

Load growth to date has mostly been associated with price decreases—but that may change

To date, load growth primarily from data centers—but also manufacturing and electrification—has mostly been either neutral or put downward pressure on electricity prices. However, the picture is complicated and likely to change going forward:

- It is not clear from the data how much *residential* customers benefit from the potential for lower rates from commercial and industrial customer load growth.
- New large-scale *transformational* growth in data centers relative to the size of existing systems is likely to lead to rate increases, unless managed carefully and transparently by utilities and regulators.
- The *indirect* impact of data center load growth is already being felt through higher prices for key equipment, and could grow alongside data center buildout.

LOAD GROWTH *CAN* LOWER ELECTRICITY PRICES IF SALES INCREASE FASTER THAN THE MARGINAL COST TO ADD NEW LOAD

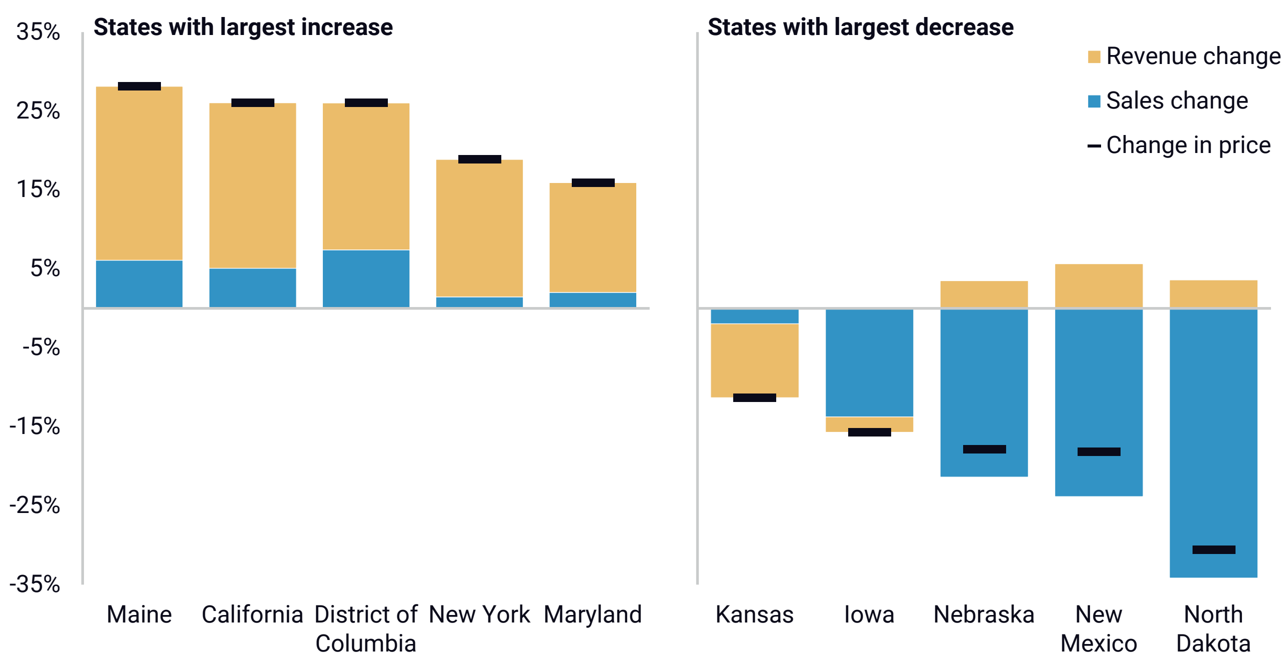
This is a counter-intuitive finding but arises when fixed costs of the system are high and the incremental cost of serving new load is low. In this situation, the new load can make better use of existing assets, spreading fixed costs out over more sales and lowering the average price for all customers. Basically, the existing spare generation and transmission capacity of the system is more than sufficient to cover the incremental new load.

The states with the largest real reduction in all-sector average electricity prices (North Dakota, New Mexico, and Nebraska) primarily reduced rate increases in sales (Figure 11). Conversely, states with the largest increases (Maine, California, and DC) saw both decreasing sales and increases in revenues. This result appears to be consistent across the full set of states and utilities at least through 2024.

FIGURE 11

Contributions to change in real average all-sector electricity price, 2019-2025

Percent change (log-based)



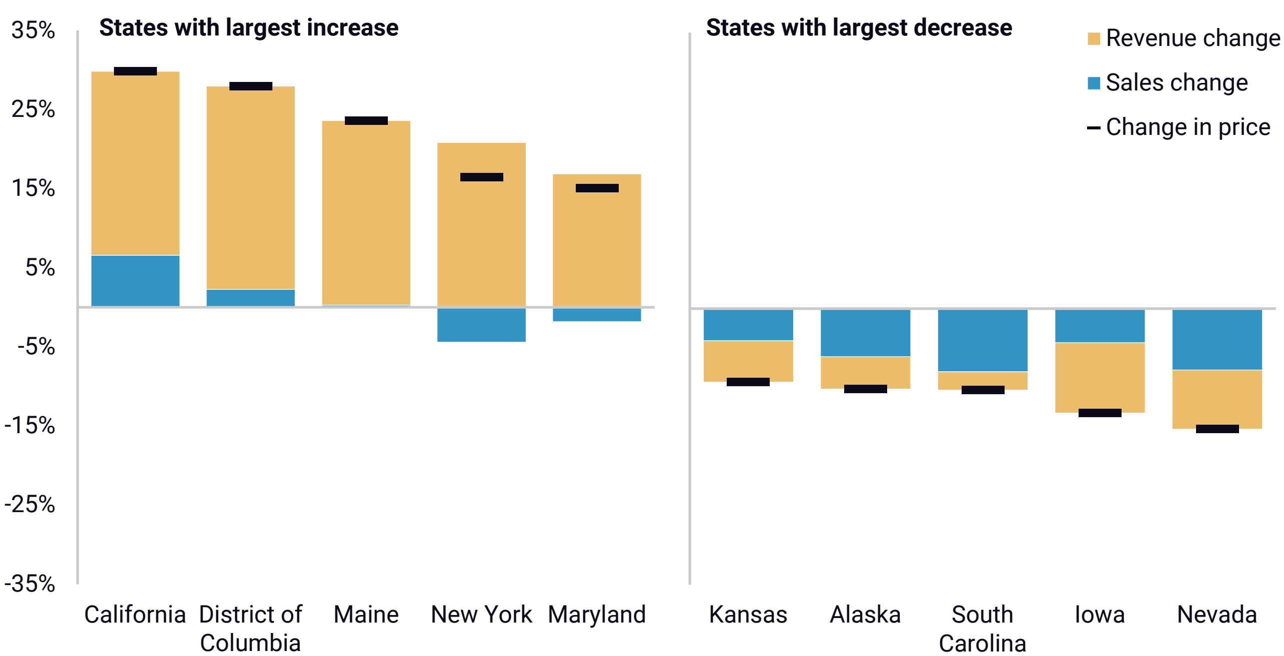
Source: Rhodium Group, EIA

However, it is not clear how much residential customers benefit from load growth concentrated in the commercial or industrial sectors. Consider North Dakota, which had the largest decrease in average all-sector electricity prices: a 26% decline since 2019 after accounting for inflation. Isolating just residential electricity prices shows a real decrease of only 9% over that same time, meaning commercial and industrial customers tended to reap most of the lower electricity price benefits of commercial and industrial load growth. The states with the largest decrease in real residential prices did so through increased residential sales, but also through reductions in revenue collected from residential customers as compared to states with the highest price increases (Figure 12).

FIGURE 12

Contributions to change in real residential electricity price, 2019-2025

Percent change (log-based)

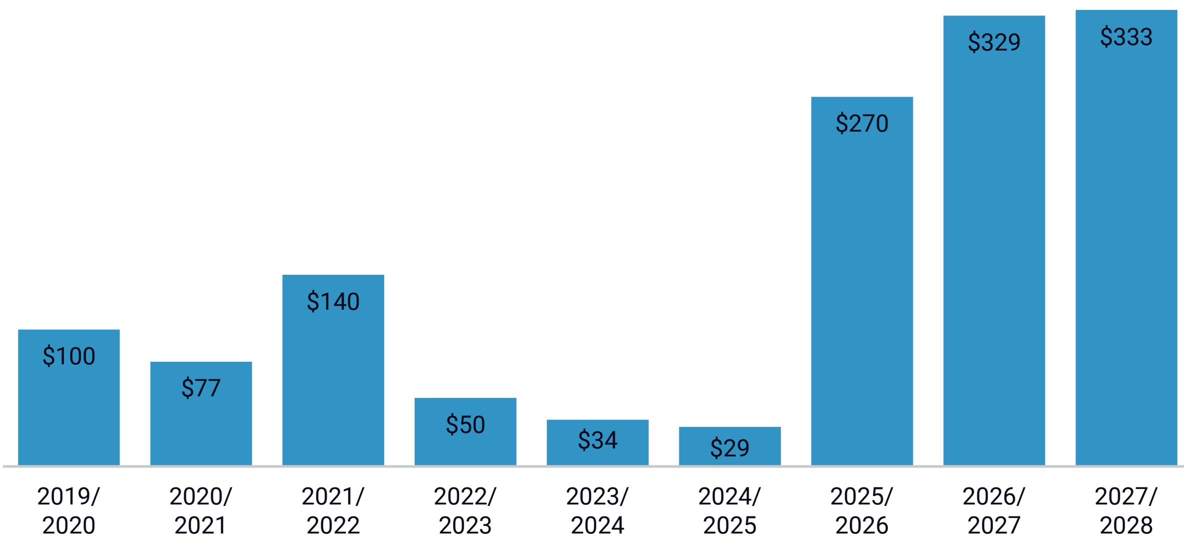


Source: Rhodium Group, EIA

DATA CENTER LOAD GROWTH IS ALREADY *INDIRECTLY* INCREASING RATES THROUGH MARKET STRUCTURES AND CAUSING SCARCITY IN COMMON EQUIPMENT

PJM's capacity market results provide the clearest example of how the crush of expected data center demand is already increasing prices for consumers, even for data centers that haven't been built yet. PJM capacity prices for 2025/2026 through 2027/2028 capacity delivery years reached record highs after almost a decade of relatively low prices (Figure 13). These prices get passed on to consumers and were a primary driver for the increase in real all-sector year-over-year electricity prices in 2025 in states exposed to capacity market pricing, namely Pennsylvania (+9%), New Jersey (+12%), and Maryland (+9%) of the PJM. Further increases are already baked in for 2026 and sustained for 2027.

FIGURE 13
PJM RTO capacity auction clearing price history
USD per MW-day



Source: Rhodium Group, PJM

Interestingly, these high prices are due almost entirely to *forecasted data center demand* in the PJM region, not from data centers that have already been built. The economic theory of the capacity market is that sustained high prices should incentivize new generators to be built. However, the speed at which forecasted data center demand has arrived has not aligned with the slow pace of capacity additions to date and the ongoing long interconnection queue wait times of PJM, even as interconnection queue reforms are being implemented.

In January, PJM issued a revised load forecast, which cut near-term peak load by 2.6%, partially through stricter vetting of proposed data center projects. This change in expected projects will directly affect the next capacity auction values that customers will pay in the coming years, highlighting how the large scale and pace of data center additions are affecting electricity prices in market regions.

Indirect impacts of data centers on electricity prices are also being observed through the crush of demand for common equipment and fuels. As noted above, the significant use of natural gas to power data centers is expected to put upward pressure on natural gas prices, increasing power costs for all consumers. In areas with wholesale electricity markets, increased demand in the short run causes operators to rely on more expensive power. As the marginal generator generally sets the wholesale power price, this increases the wholesale power price across the whole market in the short run. In an extreme case, the wholesale power price in ERCOT could rise almost 80% in 2027, in the event that electricity demand growth is twice as large as forecast.

Similarly, the rush to build new natural gas generators serving data center demand has led to a supply chain crunch and a backlog of turbine orders. This has significantly increased the price of gas turbines, which, based on information reported in regulatory dockets, has risen from around $1,000 to $1,400/kW for projects coming online in 2026 and 2027, to $2,000 to $2,500/kW for projects coming online in 2030. These higher equipment prices affect all consumers, as utilities will be paying more to build generation, even though it may not even be used to serve data centers. These trends are starting to play out for other critical grid components like large power transformers.

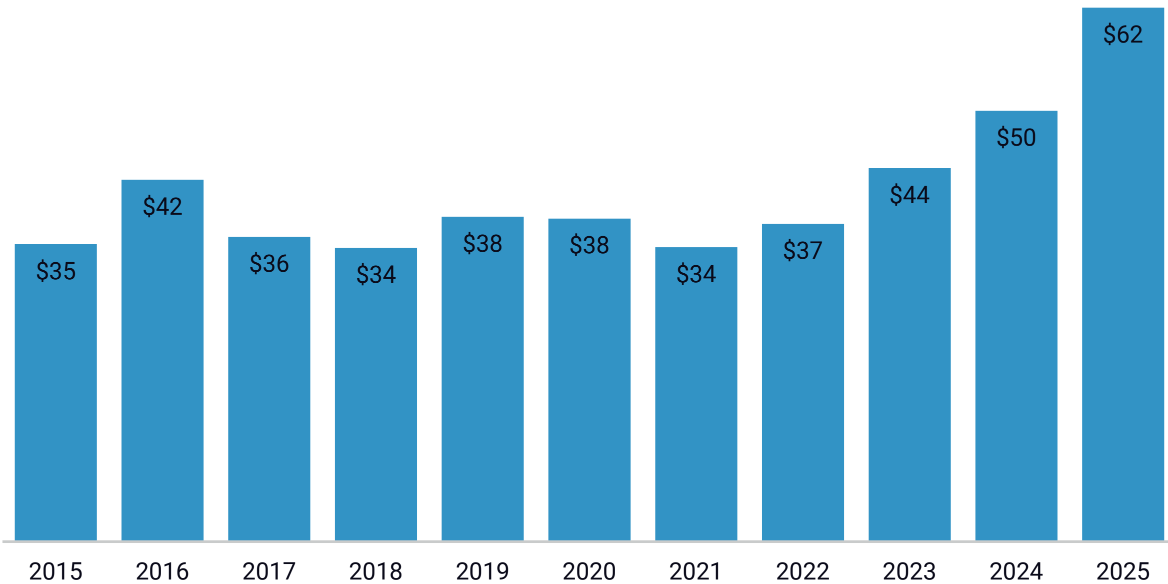
Even in cases where data centers are procuring significant amounts of other generation sources besides natural gas—such as large-scale purchases of solar power—the scale of the demand is so large that it is not likely that supply can keep up, and equipment is simply shifting away from existing projects to serve data centers. A clear example: the Louisiana Energy Users Group noted that the massive Meta data center in development was essentially "cutting in line" as Entergy was allowing them preferential access to 1.5 GW of renewable projects already in development, which other industrial customers had been waiting for to meet their own corporate sustainability goals.

Additional indirect impacts may be on the horizon—should lenders believe utilities are overexposed to the risk of a downturn in data center expansion, this could lead to lower credit ratings and higher borrowing costs for the utility, which would flow directly down to all customers.

UTILITIES ARE BEGINNING TO ACCELERATE EXPENDITURES TO MEET LOAD GROWTH

As regulated utilities generally recover capital expenditures in rates as projects come online, both the increased investment activity and the increasing cost of generators will begin to impact rates in the near term. EEI data on capital expenditures shows utilities are accelerating their investments in new generation, with $62 billion spent in 2025, a 65% increase in annual expenditures since 2019 (Figure 14).

FIGURE 14
Projected capital expenditures by investor-owned utilities, 2015-2025
Billion USD



Source: EEI

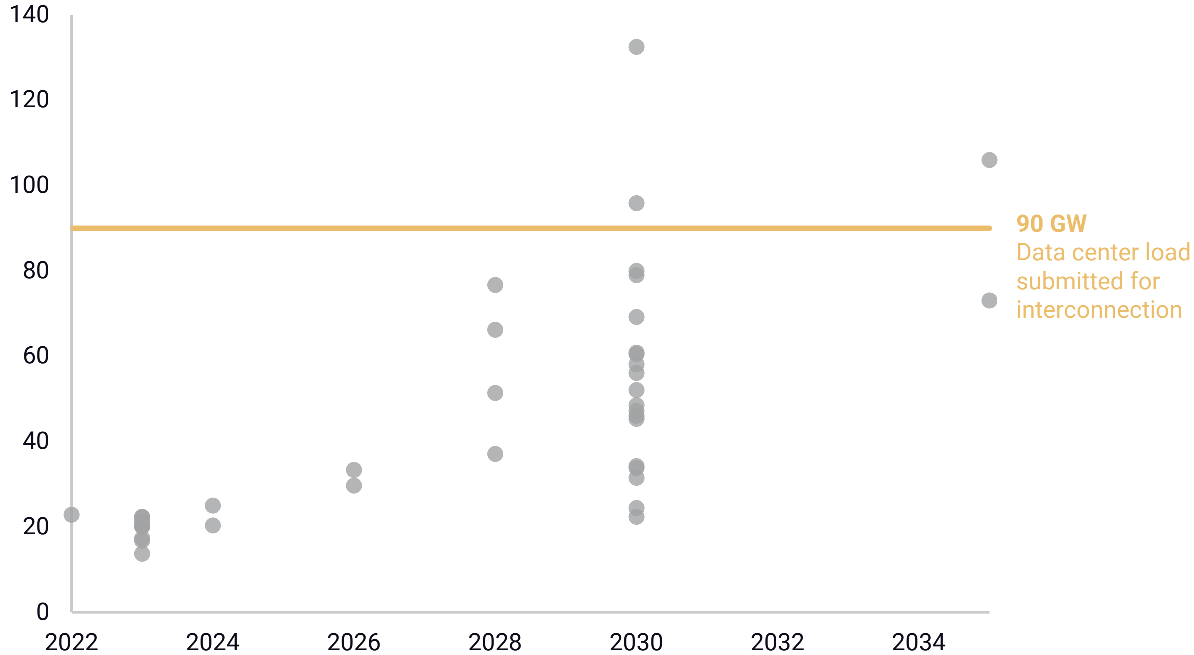
Regional investments in transmission to serve data centers in particular are also beginning to accelerate. For example, in 2022, PJM identified the immediate need for new transmission to serve growing data center load in northern Virginia, and a number of transmission lines are now in development. PJM's existing cost allocation structure means that all customers in PJM will ultimately see increased costs from these projects, even if they are primarily or even solely being developed to serve incremental data center demand in one location.

LOAD GROWTH PRESSURES ON PRICES ARE LIKELY TO CONTINUE, BUT THE MAGNITUDE DEPENDS ON A VARIETY OF FACTORS

First, the total amount of projected load from data centers is highly uncertain. Grid Strategies' load growth forecast submitted to FERC found grid operators planning for roughly 90 GW of new data center demand by 2030. Analyst expectations for how much load growth will materialize vary widely, but bottom-up estimates based on chip shipments and other approaches generally project lower demand (Figure 15), suggesting grid operators may be overestimating future load growth.

There is a chronic lack of transparency as projects are sometimes developed in secret and not revealed until construction begins. Data centers may also be shopping around, looking for the best deal, leading to double-counting among utilities. Should the upper end of data center demand be realized, the accelerated pace of generation needed will amplify the direct and indirect mechanisms through which rapid load growth impacts electricity prices. However, even if data center demand ends up lower than anticipated, it is increasingly unlikely that it will evaporate entirely. Utilities still need to make major capital investments ahead of time and will seek to recover those costs somehow if data center demand does not materialize.

FIGURE 15
Data center demand projections
GW (dots represent distinct analyst projections)



Source: Grid Strategies; Rhodium Group, The Impacts of Rising Electricity Demand from Data Centers on US Energy and Emissions

In a recent note, we modeled the impact of faster-than-expected demand growth from data centers, analyzing a scenario based on a 30% faster compound annual growth rate (CAGR) for data center demand through 2030 and 25% faster CAGR through 2035. This leads to data center demand equivalent to 14% of total US power generation in 2030 and 18% of total US power generation in 2035, relative to 10% in 2030 and 12% in 2035 in the baseline data center case. In this sensitivity, total system costs increase by 13-15% in 2035 under higher data center demand relative to our baseline scenario, but the impacts are differentiated by customer class. Commercial electricity buyers see their rates decrease by around 3% nationally on average, while residential customers see roughly equivalent bill increases. This further illustrates the complex interactions of load growth and retail price we unpacked above.

Second, much depends on how policymakers and industry respond to the challenges of meeting rapid increases in demand. On the one hand, policymakers are moving to protect customers from data center costs. The proliferation of large load tariffs, which seek to protect against stranded assets if data centers fail to use the infrastructure built for them, indicates regulators are more seriously attempting to shield other customers from this eventuality through minimum take-or-pay provisions and higher early exit fees. This should lower the risk that other customers end up paying for infrastructure if data center forecasts are too high.

On the other hand, some states are competing to land major data center projects, aiming to secure economic development benefits with tax breaks and potentially more favorable electricity terms. These are often negotiated and codified in Electric Service Agreements that are not disclosed to the public, making it difficult to determine whether individual data center projects will impact other customers' rates directly or not.

These policy fights are playing out in real time. An illustrative example: a handful of states passed laws enabling utilities to charge existing ratepayers for new generation while it is under construction and before it enters service, an accounting method commonly called construction work in-progress (CWIP). This allows utilities to lower overall project costs by avoiding the need to raise capital from more expensive debt markets, with the tradeoff of increasing rates immediately. Oklahoma passed such a law in early 2025, and Oklahoma Gas & Electric subsequently filed to collect costs from customers using CWIP for two new power plants under construction to serve data centers. Regulators subsequently denied CWIP treatment, citing the cost to customers, and OG&E is currently appealing the case to the Oklahoma Supreme Court.

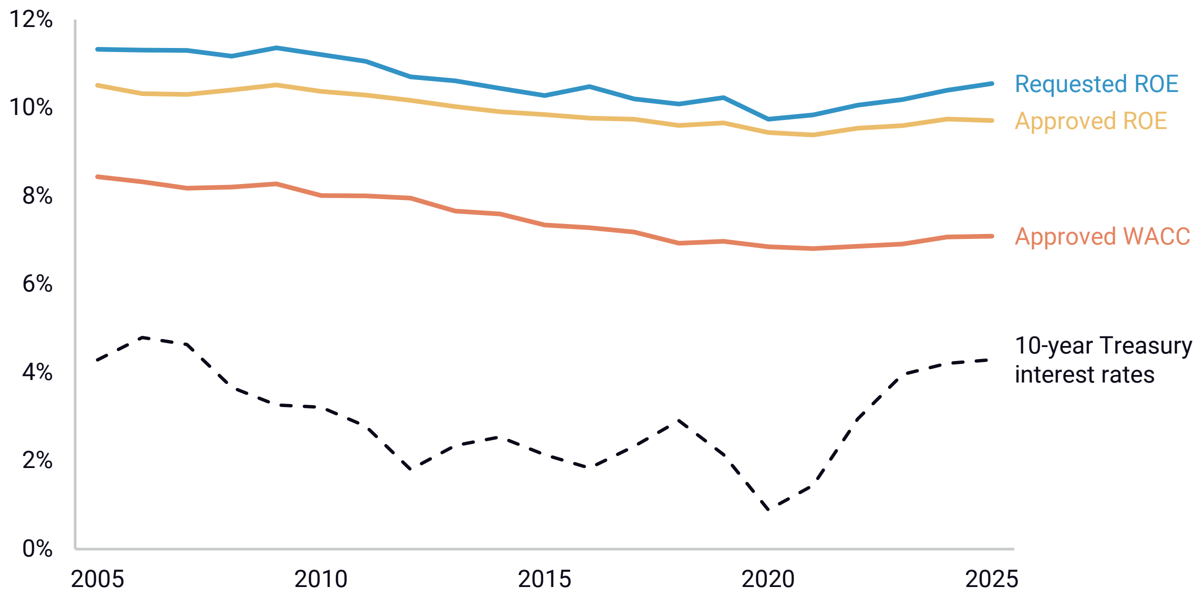
Excess utility profits are likely not a primary driver of recent price increases, but are attracting policymaker attention

Customers routinely place utility profits at the top of reasons why they think electricity prices increase: a November 2025 survey found that respondents believed utility companies' profits were the top driver of cost increases, ahead of infrastructure upgrades, data center load growth, fuel price increases, and extreme weather. While the return on equity (RoE) that regulators allow investor-owned utilities (IOUs) to earn is a readily available metric to assess, there does not appear to be a dramatic change in average utility RoE over the last decade. These have held on average around 9-10% even through the period of rising electricity prices from 2019 through 2025, increasing slightly as overall interest rates have increased (Figure 16). RoE is only part of the overall financial equation that determines actual utility profits. Cost of debt, debt-to-equity ratios, and actual amount of approved expenditures that enter the rate base each year also drive how much utilities can recover via rates.

FIGURE 16

Requested and approved return on equity (RoE), weighted average cost of capital, and interest rate benchmark for select investor-owned utilities

%



Source: LBNL

Put another way, utility RoEs themselves are unlikely to have been a major driver in increasing electricity prices over the period we consider, since those returns have stayed relatively flat. But they can have indirect effects on prices. Building more infrastructure at the same approved RoE would, all else equal, increase utility profits. This highlights the underlying economic incentive for IOUs to spend more capital, as the more they spend, the more potential profit can be earned. One analysis notes that each percentage point increase in allowed RoE leads to a 3-4% increase in capital expenditures by utilities—even as operational expenditures remain constant. This study finds that utility customers pay $3-10 billion more per year (1-3% of total IOU revenues in 2024) due to higher RoEs and the impact on capital investments. While close review of capital expenditures by regulators is intended to prevent such behavior, this finding suggests that it may not be occurring in practice.

Policymakers and consumer advocates have been examining the question of whether RoEs are too high and whether reductions could lower electricity prices. Researchers have revitalized the concept that the rate of return should be set much lower, closer to the cost of capital for utilities in the range of 6-7%, rather than the current 9-10%. Recent actions by California regulators did lower RoEs for IOUs in that state—but only by 30 basis points (0.3%). Regulators may move to slightly lower RoEs given the public and political pressure to act, but unless there is a concerted state-by-state effort to lower RoEs, it likely will not substantively change the overall trajectory of price increases nationwide.

Wind and solar growth alone are not driving higher costs—while clean energy policies in constrained locations have risen

Wind and solar deployment alone are not drivers of electricity price increases. Simple graphical comparisons and statistical correlations demonstrate that wind and solar deployment alone are not major retail price drivers, especially in areas where growth is primarily driven by market factors and not by state policies. Consider Texas, with abundant solar and wind resources and no binding clean energy policies: wind and solar as a percent of total generation grew over 13 percentage points while real retail prices declined 0.7 cents/kWh from 2019 to 2025.

High levels of rooftop solar, driven in part by net-metering policies, are associated with measurably higher retail prices in two states. Significant adoption of rooftop solar is commonly supported by state policies like net energy metering or specific carve-out requirements for rooftop solar as part of a renewable portfolio standard (RPS) or clean energy standard (CES) policy. As customers adopt rooftop solar, it reduces overall sales levels and requires utilities to recover fixed system costs over a smaller amount of sales. The result is upward pressure on retail rates for remaining utility sales. By one estimate, a five percentage point increase in rooftop solar penetration is associated with a 16% increase in retail rates.

However, narrowing the scope to just changes occurring from 2019 through 2025 shows that this is a significant issue for Maine and California, where net metered solar as a fraction of total retail sales increased by 12 and 8 percentage points, respectively. The rest of the states showed a much smaller increase, averaging just 1.4 percentage points over this time. Both states have seen recent action to revise their net energy metering programs accordingly.

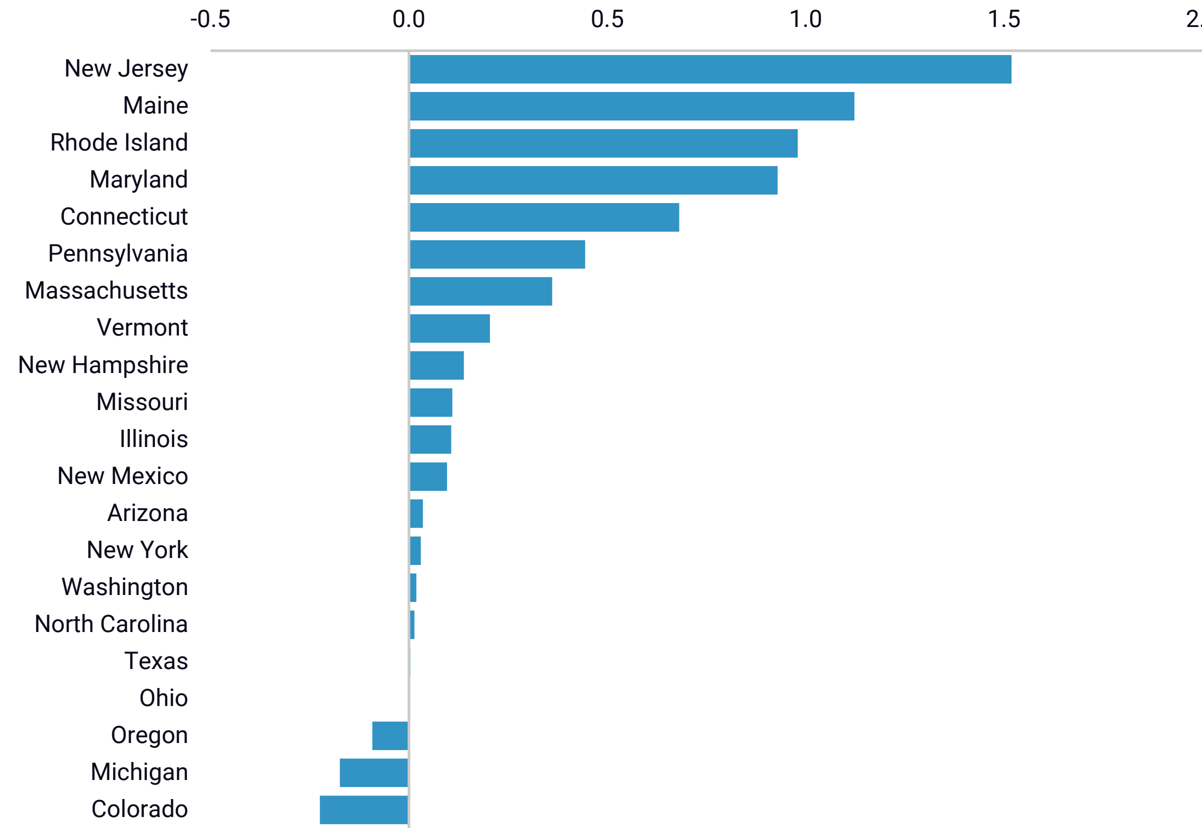
Clean electricity policies in the Northeast and Mid-Atlantic regions, with relatively lower quality resources and constrained systems, can put upward pressure on prices. While overall recent renewable deployment has not driven prices up nationwide, compliance costs have increased in some states with binding RPS and CES in recent years. This reflects a likely combination of factors: inflationary pressures and interest rates increasing the cost of renewable procurement, ongoing interconnection process reforms delaying project completion timelines, and general land and transmission constraints limiting availability and access to high-quality renewable resources.

It's important to note that the methodology for estimating compliance costs here does not directly account for comprehensive system price effects. High compliance prices reflect changes in the underlying renewable energy credit (REC) prices in those markets. However, if these state RPS policies did not exist, then the renewable resources providing the RECs would also likely not exist, and their power would need to be purchased from other resources, likely natural gas. This would have further exposed those states to higher natural gas prices in 2021 and 2022.

FIGURE 17

Change in RPS compliance costs, 2019-2025

2025 cents/kWh of retail sales



Source: LBNL, Rhodium Group

Future targets in states with existing ambitious policies may drive moderate cost pressure—but that outcome depends on policy decisions. An assessment of existing RPS and CES targets found approximately 300 TWh of new clean supply is needed by 2030 to meet these targets, roughly equivalent to 6.7% of current total generation nationwide. Most of that is driven by 2030 targets in Virginia, Illinois, and New York. The actual cost impacts of meeting these targets are difficult to anticipate. On one hand, investment in renewable resources can directly reduce exposure to likely rising natural gas prices. On the other hand, they require continued capital spending and exposure to possibly rising interest rates and challenges in building and siting new supply and transmission constraints. Much also depends on whether federal actions targeting clean energy, discussed in more detail in the next section, serve to slow down or otherwise disrupt states' abilities to adequately plan for meeting these targets in the near term.

The shifting federal policy environment is complicating planning and likely contributing to cost pressures going forward

The federal policy environment has changed substantially over the last 15 months. A number of Trump administration actions over this window, primarily targeting wind and solar resources, have increased uncertainty for investors and planners and could limit the supply of renewable resources that utilities are otherwise planning on. Tax credit changes enacted as part of the One Big Beautiful Bill Act in 2025 and new trade tariffs directly increase the cost of a number of these same resources to developers and utilities. Particularly in a new era of load growth and increasing demand for speed-to-power, these additional limitations on available supply could have meaningful impacts on future prices.

While it's generally too early for these factors to have had an impact on electricity price increases in 2025, key actions that may drive future electricity price increases include:

- **Tariffs**: New trade barriers—and uncertainty around their shifting nature—are contributing to cost pressures on key equipment. Equipment like transformers, grid-scale batteries, and solar panels is still mostly imported and is impacted by technology or component-specific tariffs as well as broader country-level levies. Underlying commodity tariffs on items like steel and aluminum affect prices for components like racking for solar panels and towers for wind turbines.

- **Tax credit changes**: The One Big Beautiful Bill Act (OBBBA), passed by Congress and signed into law by President Trump in 2025, imposed an accelerated expiration for tax credits for wind and solar while also imposing strict limitations on the use of equipment from sources like China. While we expect a rush of renewable deployment to meet strict timeline requirements, deployment in 2027 through 2030 will drop, leading to likely more expensive replacements. We found the changes to the tax code enacted by the OBBBA would increase residential electricity rates by 2-4% by 2035.

- **Administrative limitations on renewable deployment**: The Trump administration has used federal permitting decisions and other review points to otherwise disrupt or slow renewable deployment. Examples run from attempting to revoke permits for already under construction offshore wind projects and de facto banning wind and solar on federal lands to directly removing support for transmission lines closely associated with clean power. Some of this may be changing with ongoing lawsuits, but the overall chilling effect on industry investment may be difficult to unfreeze.

- **DOE actions to delay coal plant retirements**: Since May 2025, the Trump administration's Department of Energy has issued emergency orders to keep six coal plants operating past their planned retirement dates. The net costs to maintain these plants are ultimately borne by customers. The Campbell plant in Michigan was ordered to stay online in May 2025, with an estimated cost to customers of $135 million in 2025 to keep the plant online. Should the Trump administration keep all coal plants that are scheduled to retire before 2028 online, the $3 billion it would cost could increase prices more than 1% across eleven states.

CHAPTER 3

Looking Ahead: A New Era for Electricity Prices

The factors putting upward pressure on electricity rates are multifaceted, interrelated, and vary by state and region particulars. When looking holistically across all factors, it looks likely that rate increases are increasingly locked in for at least the next few years, given the number of possible drivers and the lack of possible avenues for relief—absent major policy intervention.

Utility infrastructure investment requests are up. Ongoing rate requests made by investor-owned utilities in 2025—an imperfect indicator as it excludes some storm recovery expenditures and includes generation spending for vertically integrated utilities—illustrate where investments and subsequent rate impacts may be headed in 2026 and 2027. These requests reached $18 billion in 2025, a level not previously seen this century. At least over the next few years, continued increasing infrastructure investment and associated rate pressures are likely to continue.

Load growth is here to stay. Regardless of high or low projections for data center builds, projections agree on significant new load and concomitant investment in the system to meet that load. Much will depend on how aggressive policymakers are in developing new policies to insulate residential customers from these impacts. Ratepayer protection pledges and policy action aside, this will be a growing pressure on electricity prices through increases in generation and transmission costs.

Natural gas price volatility is likely. Utilities are more exposed than ever through increased natural gas generation and increasing demand from data centers. Geopolitical factors and uncertainty seem poised to drive volatility, while increasing LNG exports put further upward pressure on prices.

Extreme storms and mitigation expenditures are certain. We don't know exactly when and where extreme weather will strike, but the overall national trend is unmistakable and associated with climate change. The increasing need for wildfire mitigation plans and costs to implement them will begin to hit customers in the West over the coming years. Utilities seeking to avoid major storm damage costs will instead face expenditures to underground lines and harden system assets to improve reliability.

Increasing uncertainty in policy and geopolitical factors looks to sustain. Beyond major disruptions to oil and LNG shipments, the war in Iran is expected to continue to have follow-on effects up the supply chain for key grid equipment and electricity-generating components, including increasing inflationary pressure. The threat of tariff changes continues to inject uncertainty into future prices for key components.

For policymakers, this unfortunately means there are no quick fixes to be had. Market fundamentals alone will not deliver near-term rate relief. Even if natural gas prices are elevated for longer, renewable capital costs will likely remain elevated in the near to medium term due to geopolitical uncertainty, tariffs, inflation, supply chain limitations, and high interest rates. Increased investments in domestic supply chains, workforce development, and infrastructure hardening are long-term plays that will take multiple years to see impacts. Rate freezes can offer immediate relief from increases, but do not otherwise address the underlying structural factors.

Some states are pursuing securitization of existing infrastructure or other cost liabilities, such as unrecovered costs from storm damage, to lower customer costs. This allows utilities to take costs out of the rate base and instead issue bonds with a lower interest rate than the utility's cost of capital. West Virginia enabled securitization in 2023, and regulators recently approved securitization of up to $2.3 billion of costs, including from storm damage, high fuel prices, and investments to meet environmental regulations.

Much will depend on how policymakers respond to the increasing system pressures due to data center growth in specific regions. Regulators are getting ahead of risks posed by large loads, primarily through new and revised tariffs specifically for large load customers, as mentioned above. For example, Michigan regulators recently approved a new rate class for loads greater than 100 MW, requiring a minimum commitment of 15 years, minimum monthly billing of 80% of requested capacity regardless of actual usage, and an early exit fee equal to the minimum billing times the number of years left on the contract. As of March 2026, 20 states have approved at least one large load tariff, and nine more have tariffs under consideration. Other novel actions seek to cordon off utility expenditures for data centers from other customers entirely. NIPSCO in Indiana recently gained regulatory approval to create a separate new affiliate company focused solely on investing an estimated $7 billion in new generation and transmission to serve data centers.

An emerging trend is leveraging the flexibility of loads like data centers to put downward pressure on prices through increased usage of existing grid assets. Virginia recently enacted a law giving regulators the authority to require grid asset metric reporting from IOUs and include targets when considering cost recovery requests. More broadly, states are signaling their desire to take a more active role in shaping PJM market design. All 13 governors representing states within the PJM region signed on to a White House "statement of principles" letter urging PJM to develop a separate capacity market for data centers to insulate existing customers from the market impact of data center demand on capacity prices.

If policymakers can adequately insulate ratepayers from infrastructure expenditures to meet large loads, this could remove one driver of cost increases and, in the most effective cases, lead to downward pressure on prices from more efficient use of the existing system.

About Rhodium Group

Rhodium Group is an independent research provider with deep expertise in policy and economic analysis. We help decision-makers in both the public and private sectors navigate global challenges through objective, original, and data-driven research and insights. Our key areas of expertise are China's economy and policy dynamics, and global climate change and energy systems. More information is available at www.rhg.com.

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