LAWRENCE BERKELEY NATIONAL LABORATORY

Retail Electricity Price Trends and Drivers:

Data Update−2026 Edition

Ryan Wiser, Galen Barbose, Will Gorman, Eric O’Shaughnessy, Sydney Forrester, Paul Donohoo-Vallett, Peter Cappers, Jeffrey Deason

Lawrence Berkeley National Laboratory

Ryan Hledik, Long Lam

The Brattle Group

April 2026

This work was funded by the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The views and opinions of the authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or The Regents of the University of California.

Image source: OpenAI DALL-E

Objectives and Scope of Study

Context: Retail electricity prices are of national concern, but trends and drivers are complex and vary across states

Study Scope

Summarize trends in retail electricity prices

- National- and state-level trends (not utility-specific) since 2010, but focus on last year and since 2019
- Data sometimes presented in nominal terms but in most cases in real (inflation-adjusted) terms

Assess drivers of recent price changes

- Explores some of the most-common drivers of state-level price changes over the past year
- Describes relationships over longer period, 2019-25
- Does a deeper-dive on the impact of load growth

Study Limitations

- Is not definitive: analyzes subset of drivers from available data, **emphasizes need for continued research**
- **Does not analyze drivers in each individual state**; analysis focuses on broader trends
- Scope **is centered on retail prices**; studying bills and the costs and benefits derived from price increases are also important but not covered
- **Does not predict future** price trends or assess possible future price drivers, though does provide 2026 preview
- Focuses on understanding the nature and scope of price changes, **not measures to ameliorate any increases**

Findings underscore the **diverse set of retail price determinants** and highlight the need for continued efforts to inform policy and ensure affordability

Contents, Methods, and Data

- **Trends in retail electricity prices**
  - National & state-level trends: 2025 vs. 2010, 2019, 2024
  - Prices: all-sector average and residential prices
  - Affordability: costs relative to income & other expenses
- **Drivers of price changes from 2024 to 2025**
  - State-level price changes: all-sector avg. & residential
  - Primary drivers and story-lines from previous year
  - Longer-term context offered to understand latest year
- **Medium-term relationships: 2019 to 2025**
  - Update and expand data on medium-term relationships
- **Deep dive: impact of accelerated load growth**
  - Longer- and shorter-term impacts
  - State and regional case studies
- **Early 2026 indicators and IOU rate requests**
  - Early pricing data from 2026
  - Data on historical and recent rate increase requests

Primary Methods and Data

Synthesis of publicly available data[1]

- EIA: retail prices, sales, generation
- FERC Form 1: investor-owned utility costs
- ISOs/mkt. monitors: trans., capacity, energy costs
- BEA/BLS: income, expenditure, price indices
- S&P: rate and ROE requests and approvals

Review of literature; case studies

- Regulatory filings & orders (wildfire & storm costs, case studies, year-over-year changes)
- Other literature (e.g., RPS & net-metering costs)

Selected timeframes for data synthesis

- 2025 vs. 2024 for the most recent, latest year
- 2025 vs. 2019 for trends that span COVID years
- 2025 vs. 2010 to provide longer-term context

[1] Unless otherwise specified, data and analysis includes all 50 states and DC. Inflation adjustment uses regional and national CPI data from BLS; adjusting for inflation based on other common price deflators does not make a material difference to the core findings and results.

Additions in this 2026 data update of retail price trends and drivers

This briefing deck **updates** and **builds** on LBNL/Brattle's 2025 work, which included a journal article, briefing materials, and a data tool; and LBNL work published in 2024

Broad updates and additions in this 2026 edition include:

Data updates to include retail price trends and drivers through year 2025 *(most slides)*	Enhanced focus on price trends from 2024 to 2025 and key YoY drivers *(slides 16-25)*	Expanded focus on load growth, and impacts on retail electricity prices *(slides 42-54)*	Additional data on IOU rate increase and ROE requests and approvals *(slides 55-60)*

Expanded data related to retail price trends and drivers:

- Data on electricity burden and affordability trends *(slides 14-15)*
- Natural gas impacts over the longer- and shorter-term *(slides 19-20, 37)*
- Regional capacity-prices and related impacts *(slides 21-22, 40)*
- Regional transmission costs and related impacts *(slides 24,29,30)*
- Regional distribution costs and related impacts *(slides 23,28,30)*
- Carbon policy impact on generation costs *(slides 35)*
- Coal and nuclear generation, relationship to prices *(slides 38-39)*
- Utility ownership, regulation, and financing *(slides 41)*

Trends and Drivers of Retail Electricity Prices: Summary of Key Findings

The Crisis View

Nominal Prices Up 33% since 2019
National residential electricity prices surged from 2019 to 2025.

Regional Price Spikes
Larger increases in California and states in the Northeast & Mid-Atlantic.

High Electricity Burden
One-third of households dedicate over 5% of their income to electricity.

The More Nuanced View

Prices Largely Tracked Inflation
All-sector average prices are only up 3% since 2019 in real dollars.

Real Prices Down in 29 States
A majority of states saw a decline in inflation-adjusted prices (2019-2025).

Electricity Burdens Are Lower than in 2019 in Most Regions
Total bills as a fraction of income are near all-time lows

What's to Come

Record levels of IOU rate increase requests & regulatory approvals suggest additional near-term price increases absent policy/market actions.

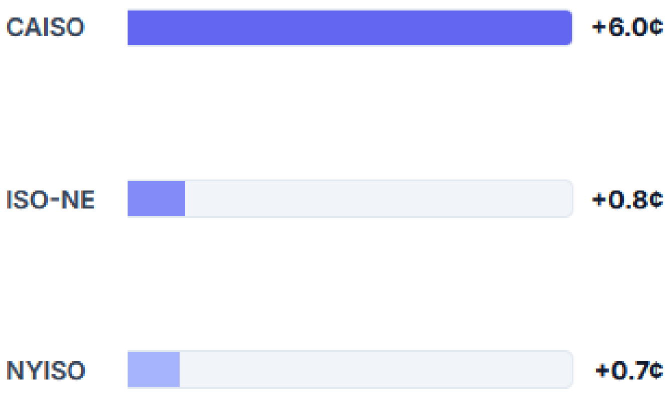
REQUESTS (2025) **$18B**

APPROVALS of requests (2021-25) **64%**

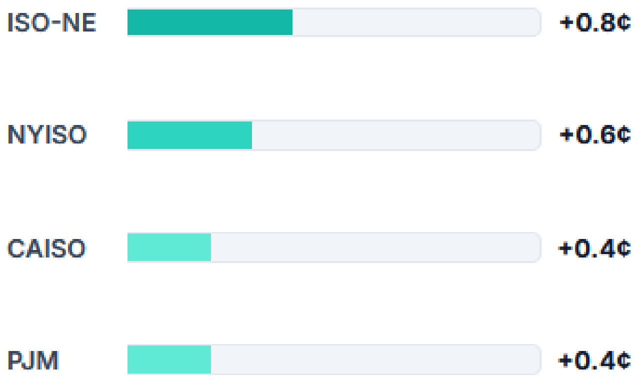
Primary Drivers of Inflation-Adjusted Price Increases

(2019-2025, focused on regions with significant price increases)

Distribution & Business Operations



Transmission



Clean Energy Policy
Some states in **ISO-NE, NYISO, PJM, CAISO** saw increases up to **3 ¢/kWh** due to RPS, NEM, and cap-and-trade

Additional State-Level Price Drivers

Customer Load
Load growth generally **reduced** average prices, but **not** in PJM starting in 2025.

Natural Gas
Longer term: reduced prices. 2025 vs 2024: increased prices.

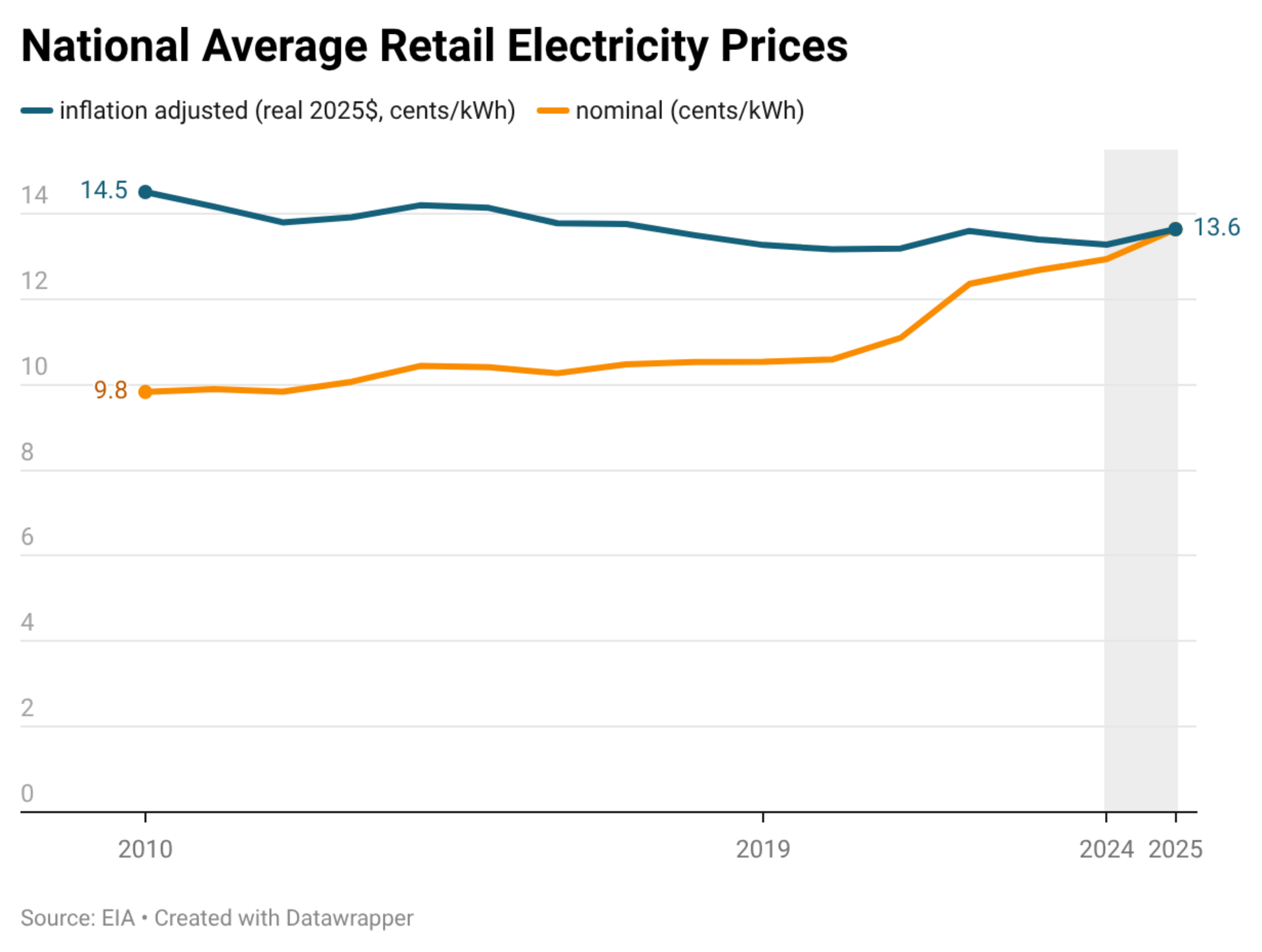
Generation Mix
Some evidence that nuclear/coal and wind/solar (outside of RPS) put downward pressure on prices in some states.

Trends – *Level-setting on historical retail prices*

National-average nominal retail prices have spiked in recent years, though the increases have largely tracked inflation… but with a bump 2025

- All-sector average retail prices increased in 2025 vs. 2024: **5.3%** in nominal terms, **2.6%** in inflation-adjusted terms
- On a longer-term basis:
  - In nominal terms, average prices increased **29%** from 2019 to 2025, and **39%** since 2010
  - Adjusting for inflation, real prices in 2025 were **3% higher** than 2019, and **6% lower** than 2010
- Note: Recently, electric costs have contributed 3-4% to overall inflation[1]

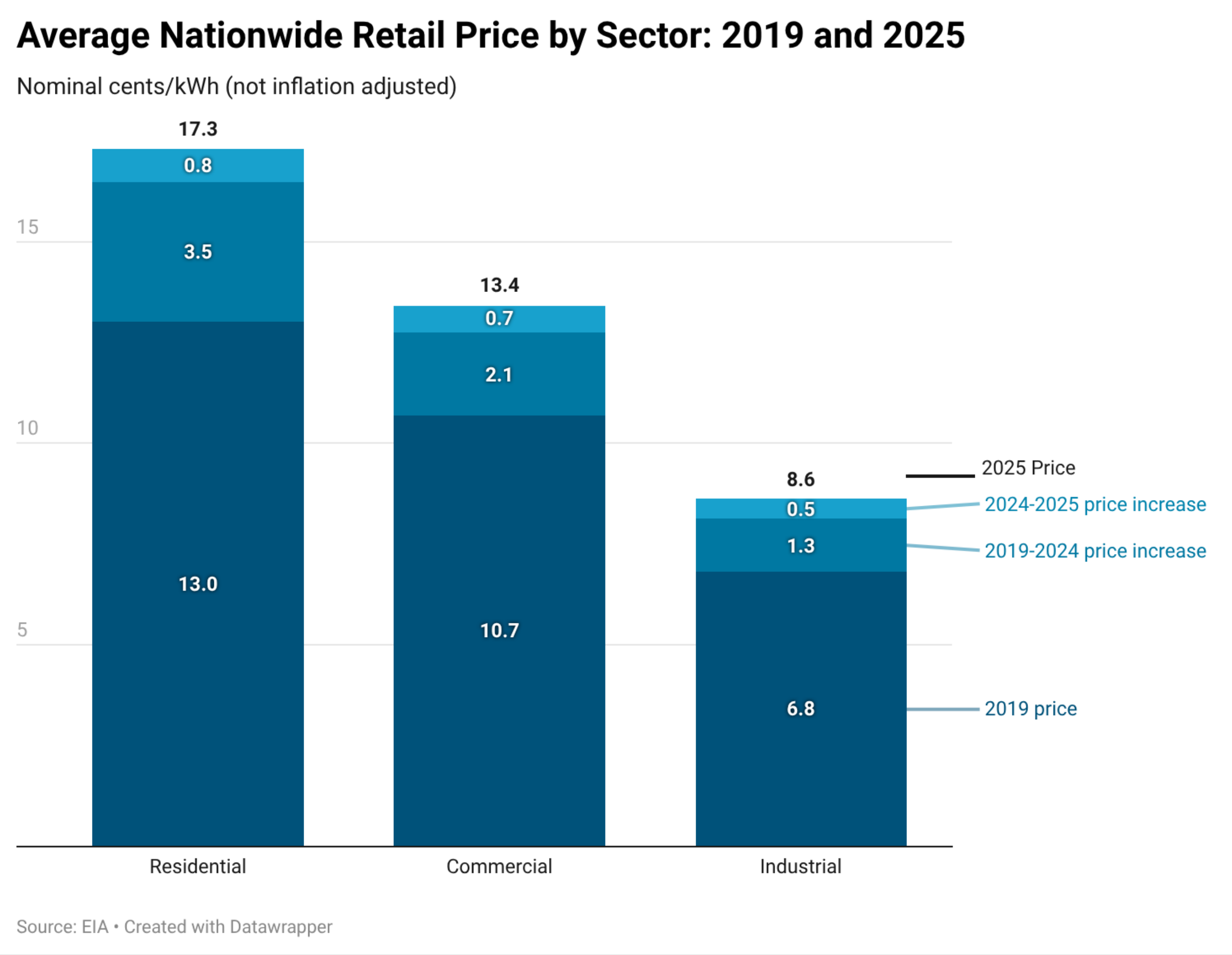
Represents the "all-in" price, equivalent to total customer bills (including volumetric, demand, and fixed charges) divided by total retail electricity sales, and covers all costs associated with the provision of retail service (generation + transmission + distribution)



[1] Based on LBNL calculation using data and methods from BLS.

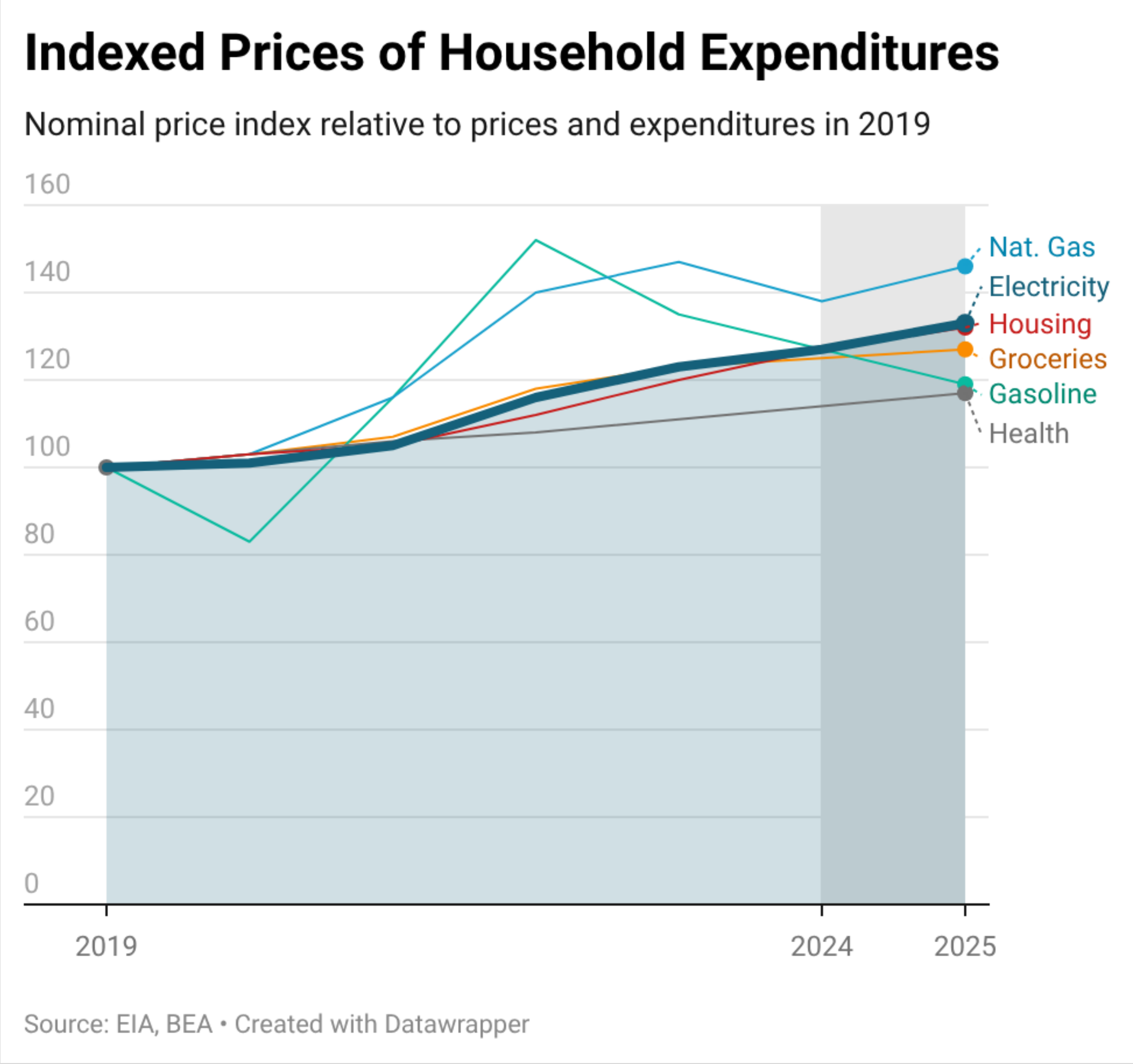
Residential customers have faced larger recent retail electricity price increases than have commercial and industrial customers

- Residential prices are higher and have risen faster than C&I
- From 2019 to 2025 (nominal):
  - Residential up: 33%
  - Commercial up: 26%
  - Industrial up: 27%
- Continues a longer-term trend of increasing gap between residential and C&I prices
- From 2024 to 2025 (nominal):
  - Residential up: 5.0%
  - Commercial up: 5.2%
  - Industrial up: 6.0%



Residential retail electricity price increases have been significant: broadly in line with some other household expenditures but higher than others

- The figure shows indexed residential electricity prices compared to other major household expenditures (not inflation adjusted) since 2019
- From 2019 to 2025, national-average residential electricity prices increased more slowly than residential natural gas, similar to housing, and more rapidly than health, gasoline, and groceries
- Broadly consistent with these trends, national-average residential electricity prices increased faster than economy-wide inflation from 2019 to 2025, rising 5.6% in real inflation-adjusted terms

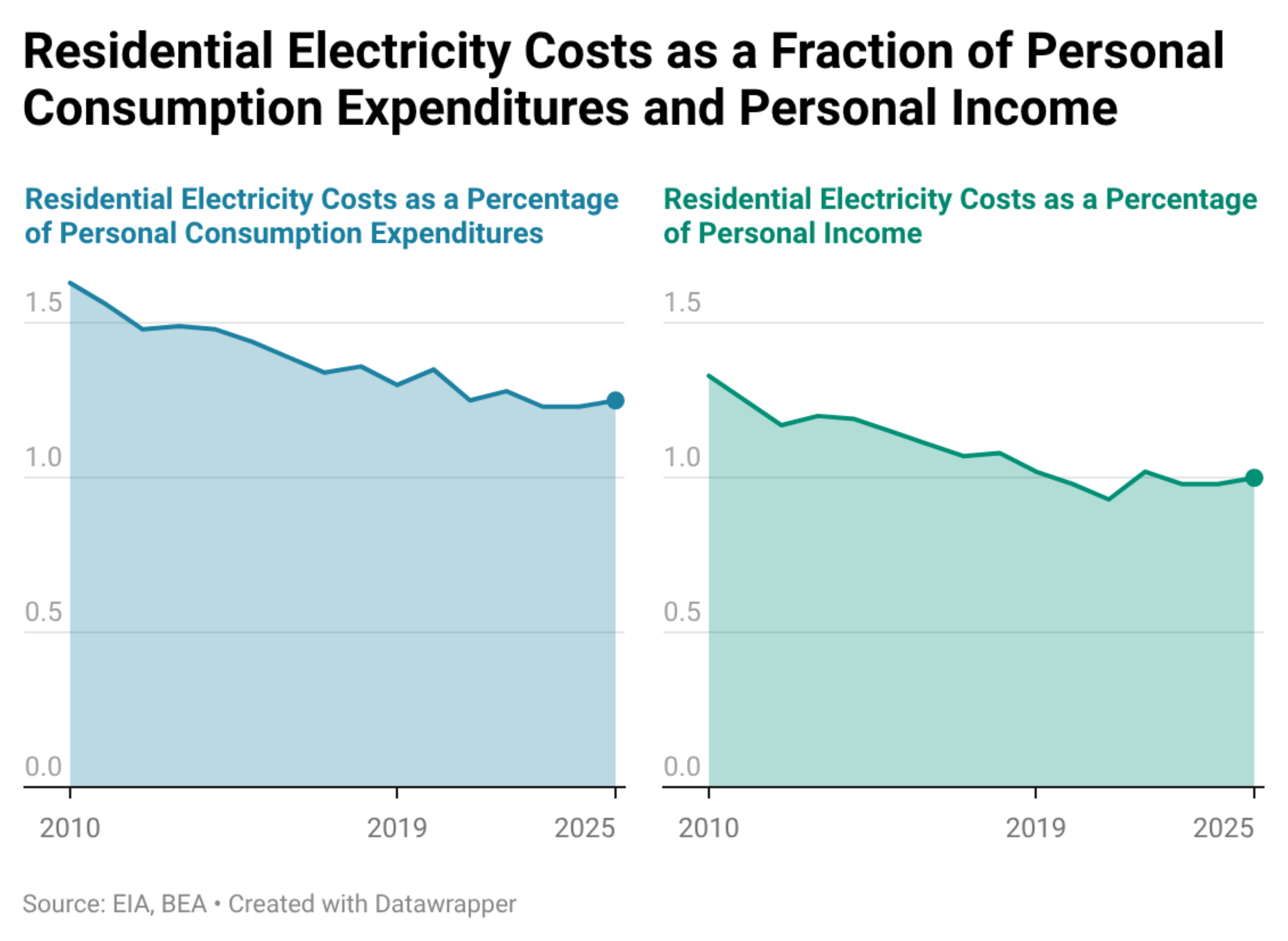


National residential electricity costs as a fraction of personal expenditure *(left)* and income *(right)* trended down for decades, but increased in 2025

- Total residential electricity costs as a fraction of personal expenditure = 1.25% in 2025, near an all-time low—*but slightly above the 2024 level*

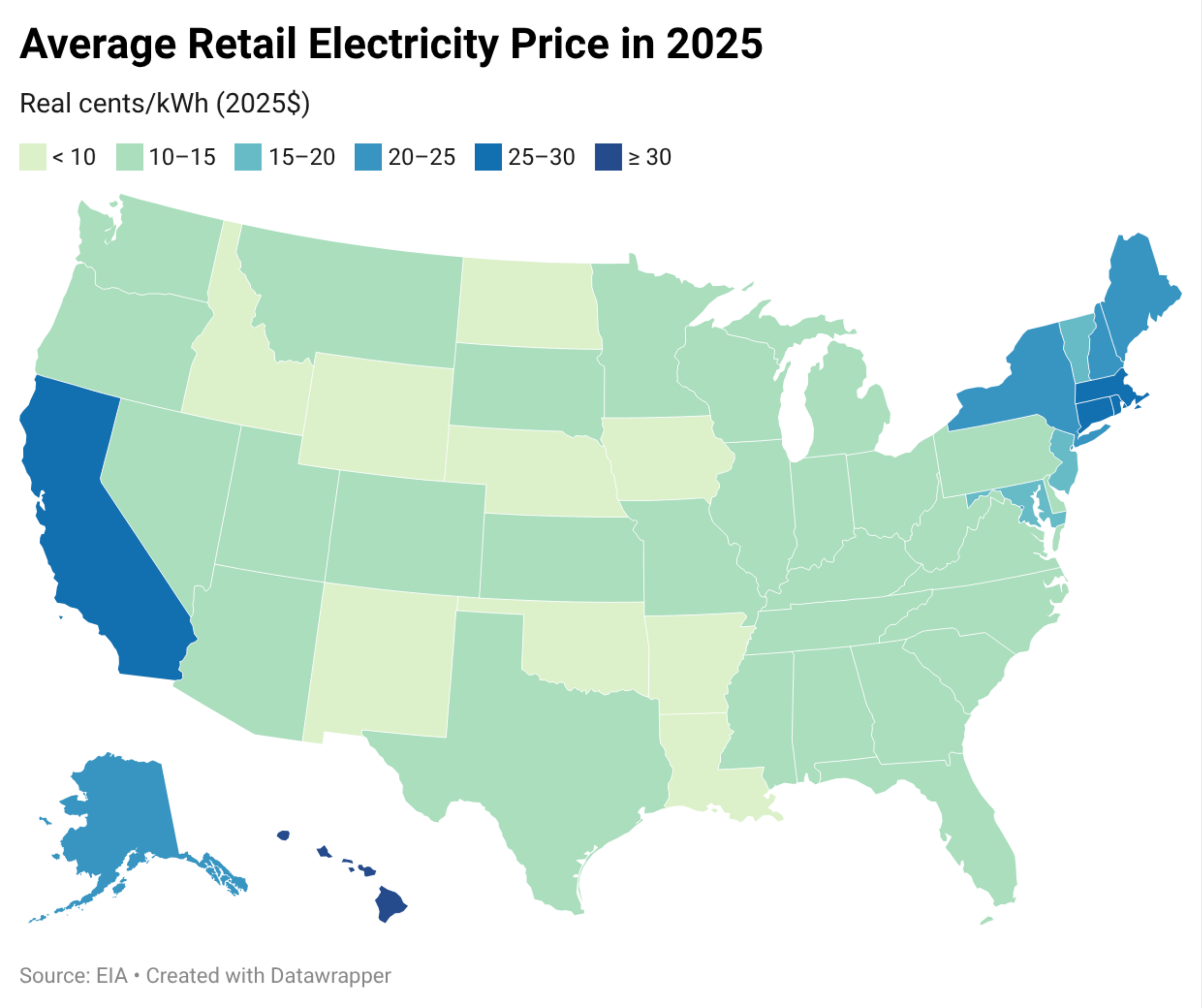
- Total residential electricity costs as a fraction of total income was also near an all-time low, at 1.0%—*but largely flat in recent years and with a slight increase in 2025*

Note: Costs as a percent of income use personal income estimates from BEA, which are generally larger than household income estimates reported in the U.S. Census (see Katz). The percentages reported on this slide also differ from the electricity burden estimates reported later, which are based on consumer survey responses. Both estimates on this slide use summed totals for all households, so reflect economy-wide aggregate impacts as opposed to household averages or medians.



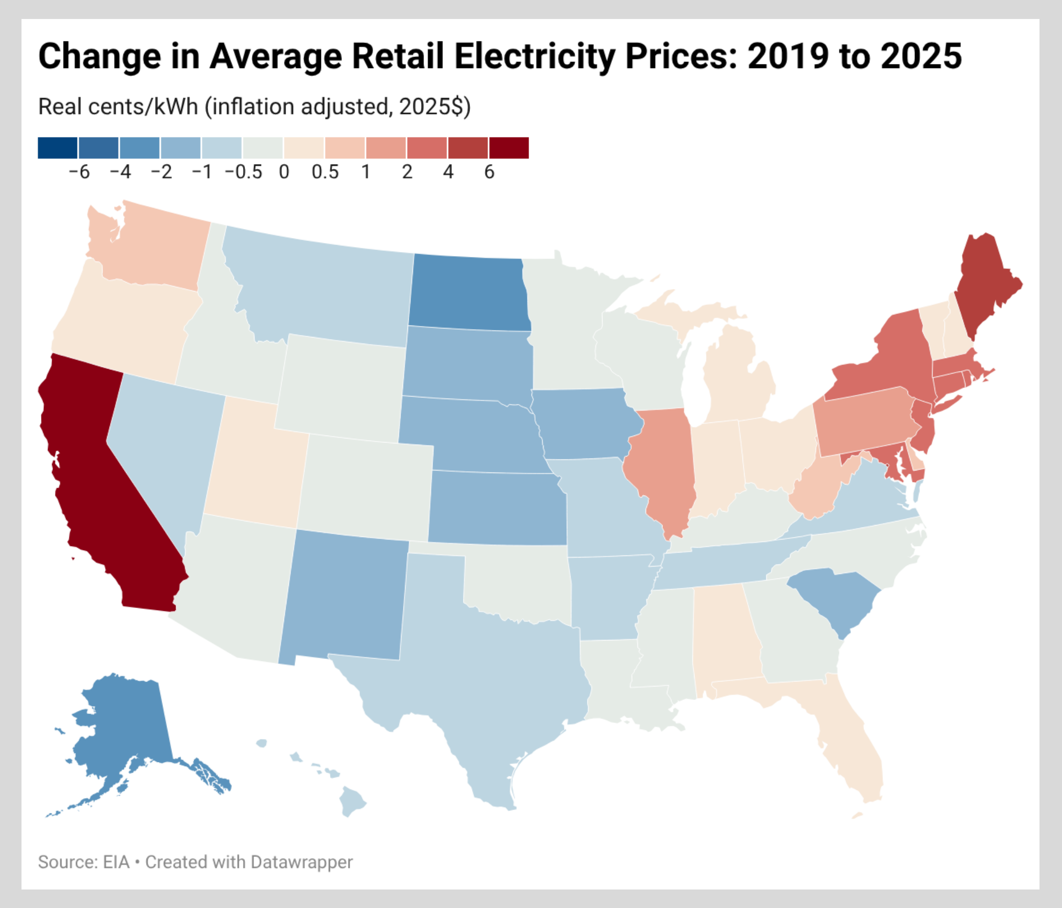
National trends mask stark differences in state-level all-sector average retail electricity prices in 2025

- Map depicts all-sector average retail electricity prices, in 2025
- Highest prices were in Hawaii, California, the Northeast, Alaska, some states in the Mid Atlantic
- Around 90% of the lower-48 landmass and ~75% of the population are located in states with all-sector average prices below 15 cents/kWh
- As shown earlier: residential electricity prices are higher than all-sector averages

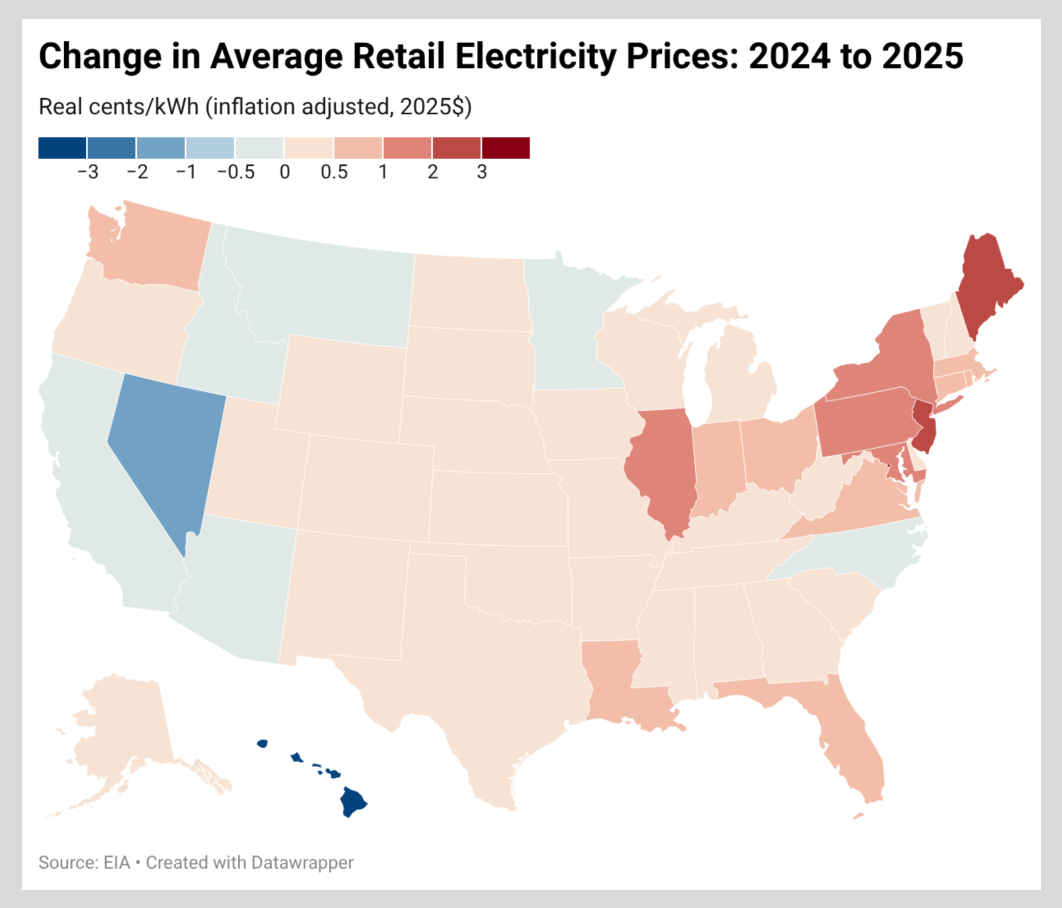


Changes in <u>average</u> state-level, <u>inflation-adjusted</u> retail prices vary widely: many more states with increases in last year *(right)* than 2019-2025 *(left)*

2019-2025: 29 states with decreases; largest <u>increases</u> in California, Northeast, some states in Mid-Atlantic, West, Great Lakes

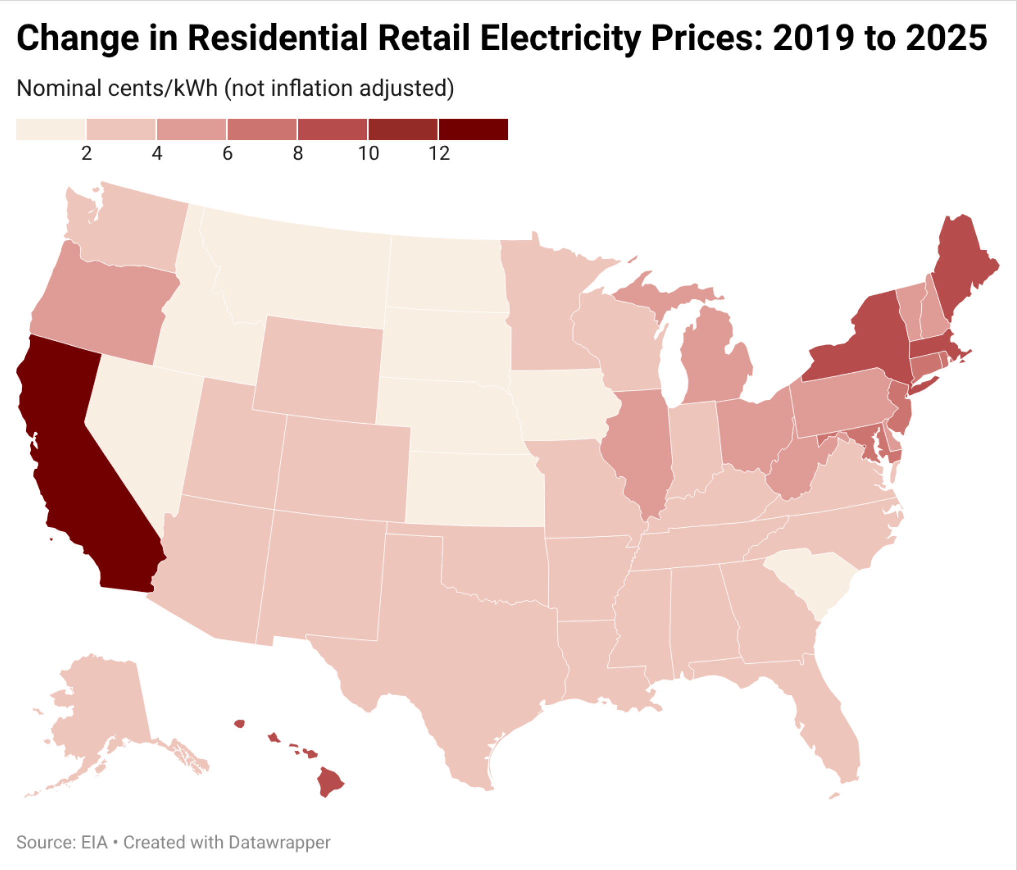


2024-2025: 43 states/DC with increases; largest <u>increases</u> in Northeast, Mid-Atlantic, Great Lakes, some in Southeast and West

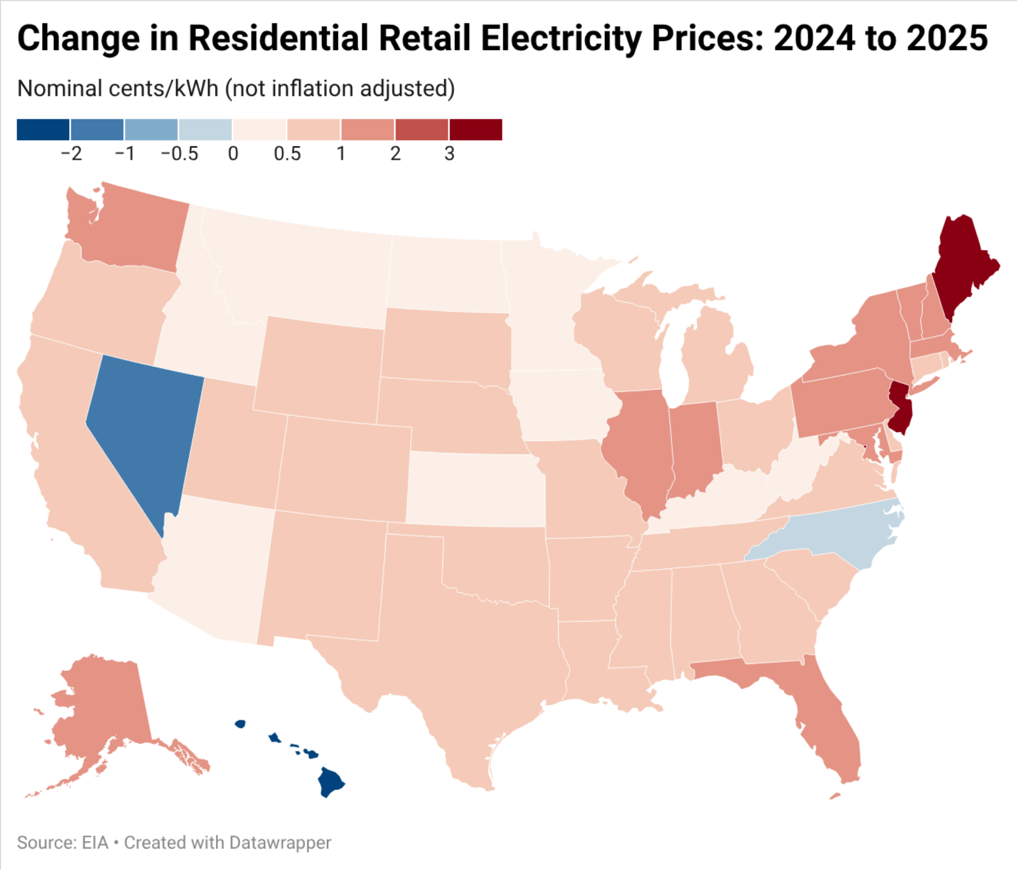


Turning to residential prices, customers may pay more attention to rapid increases in nominal *(shown below)* than to inflation-adjusted retail prices

2019-2025: All states with **increases**; largest increases in California, Northeast, some states in Mid-Atlantic, West, Great Lakes

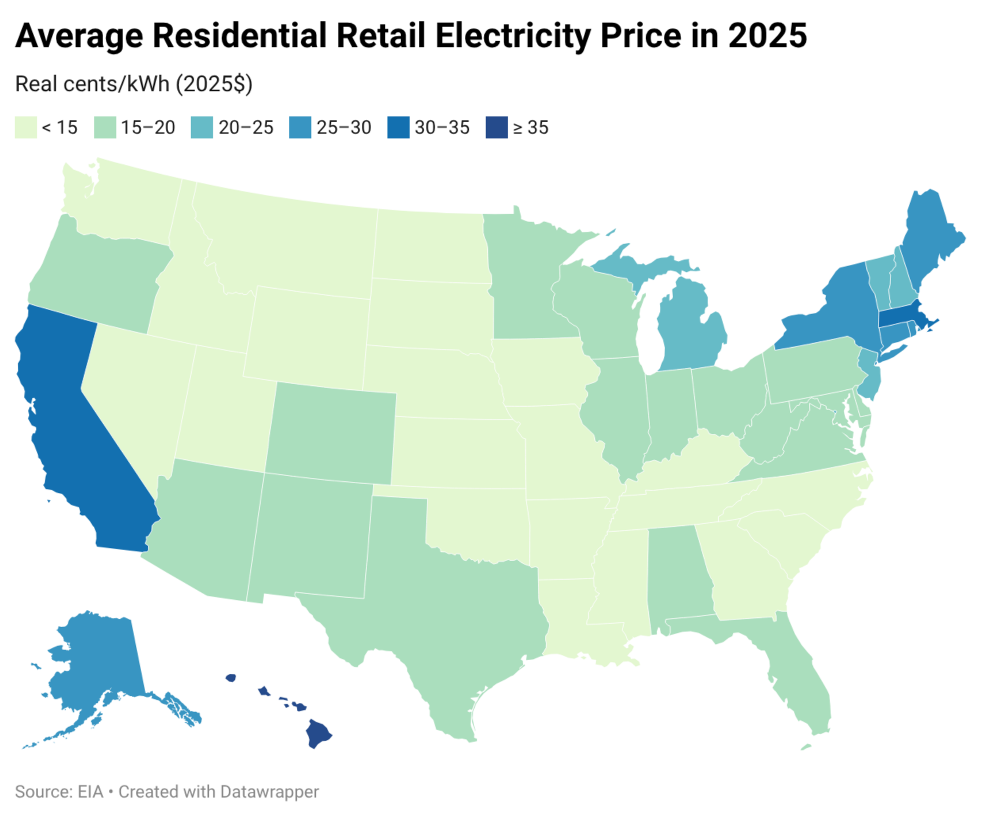


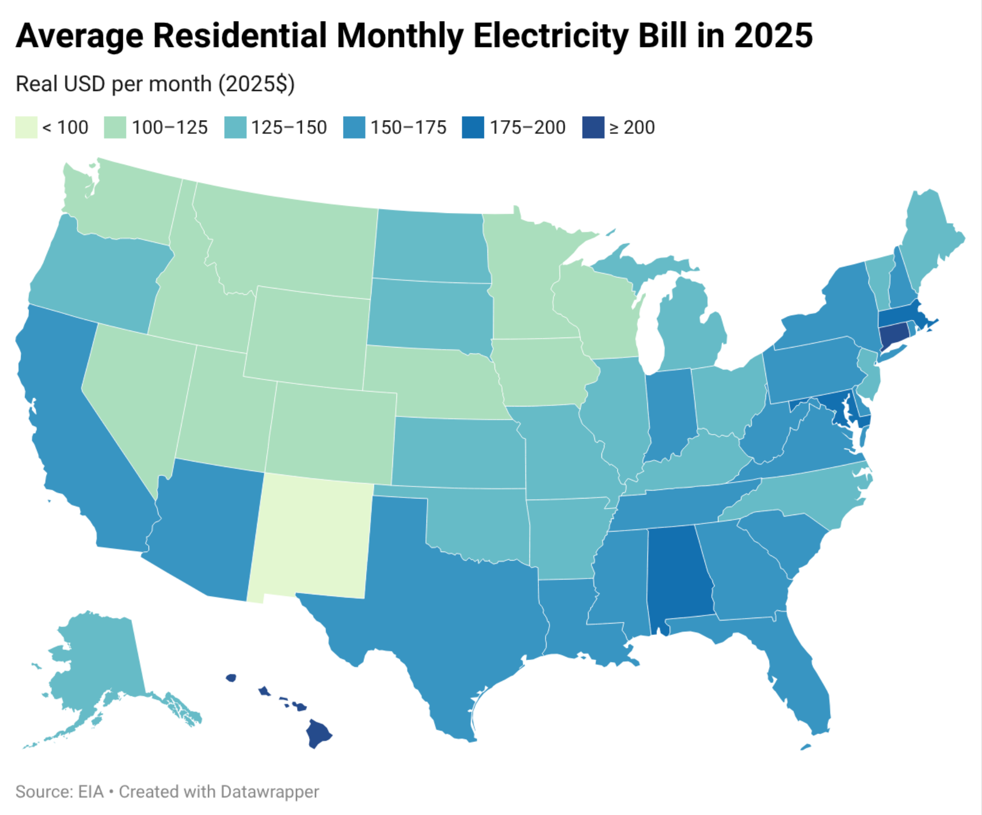
2024-2025: Most states with **increases**; largest increases in Northeast, some states Mid-Atlantic, Great Lakes, Southeast, West



Household affordability is also impacted by consumption: states with the highest prices *(left)* in 2025 may not have the highest bills *(right)*

- The highest average residential **prices** in 2025 were in HI, CA, the Northeast, and Alaska
- Highest monthly **bills** occurred across a diversity of states; California not an outlier on bills
  - *Note that the residential bill figure is electricity-only, not all household energy, and is thus impacted by the prevalence of electric heating; states with more natural gas or fuel oil heating (notably, the Northeast, Midwest, California) have additional energy costs not shown here*[1]





[1] For more on total household energy bills, see EPRI (2025)

Regardless of aggregate national and state-level price trends, electricity expenditures are a major hardship for some households

- "Electricity burden"[1]: Nationally, residential bills as a fraction of income **have generally declined over time**, through 2024 *(latest year available)*
- In more-recent years, values have stabilized for most income brackets, but appear to have continued to decline for the lowest-income households
- Regardless of time trends, **average electricity burdens are > 5% for lower-income households** *(~1/3 of all households have incomes <$50k)*
- Increasing burdens likely for 2025 given price trends
- More broadly:
  - 1-in-6 households are behind on their energy bills; utility arrearages reached $21 billion in May 2025[2]
  - Among a sample of 92 utilities (50M customers), disconnection rates declined from 2019 (~0.4%) to 2020 (~0.1%) with pandemic-related protections; they have since increased but remained below 2019 levels through the end of 2024 (~0.3%)[3]

Residential Electricity Bills as a Fraction of Income, by Household Income Bracket

Electricity burden for average household in each income bracket

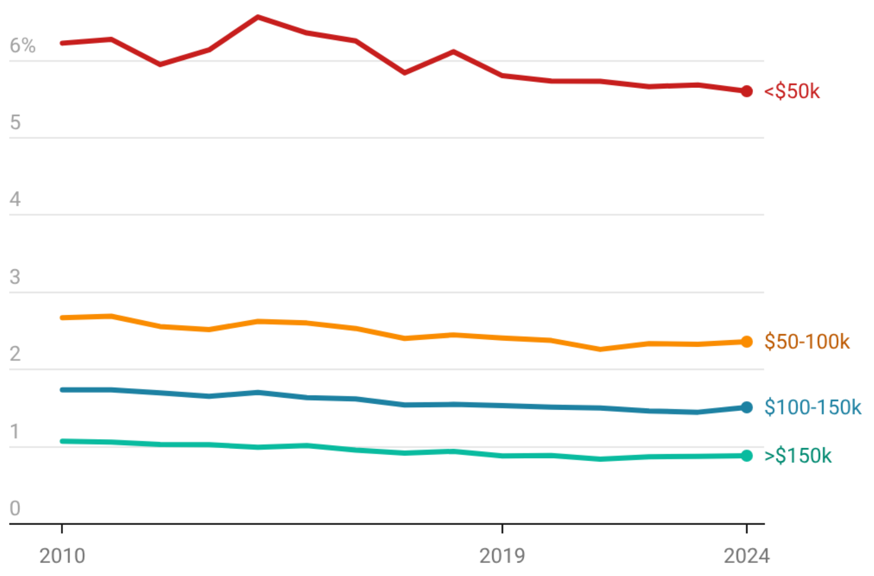


Figure excludes the bottom and top quartiles of data in each income bin to create more stable results. Data are from the BLS Consumer Expenditure Survey. Electricity costs are based on respondent reports of costs over three-month periods and therefore likely entail some degree of recall error. Further, because the survey data are not panel data, some changes over time may reflect spurious changes in the underlying sample. Results should be interpreted with care.

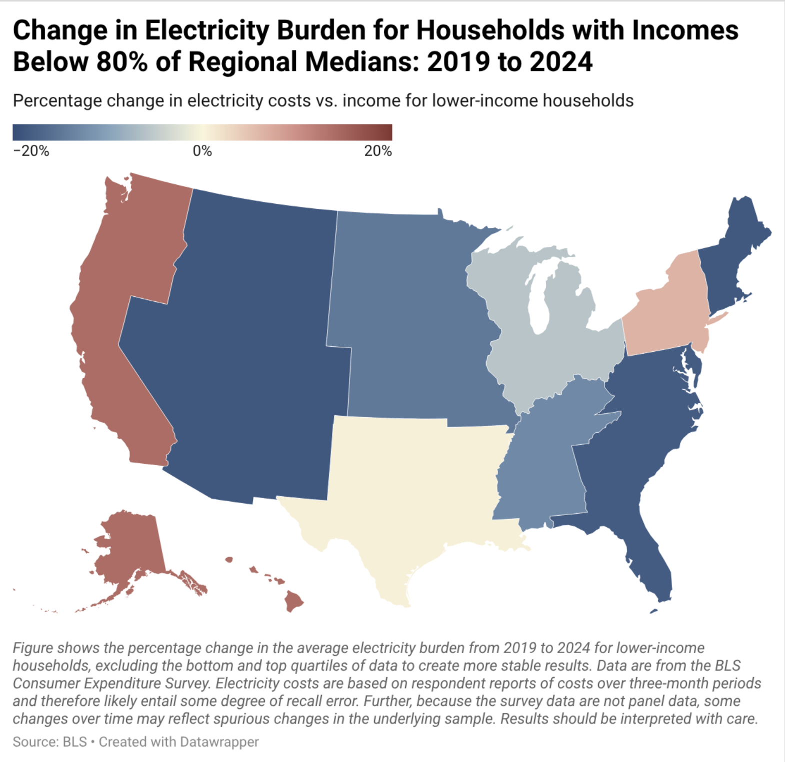
Source: BLS • Created with Datawrapper

[1] *Focused solely on electricity impacts, not broader concept of energy burden; based on BLS's "Consumer Expenditure Survey", with data available through 2024;* [2] NEADA (2026); [3] Carley & Konisky (2026)

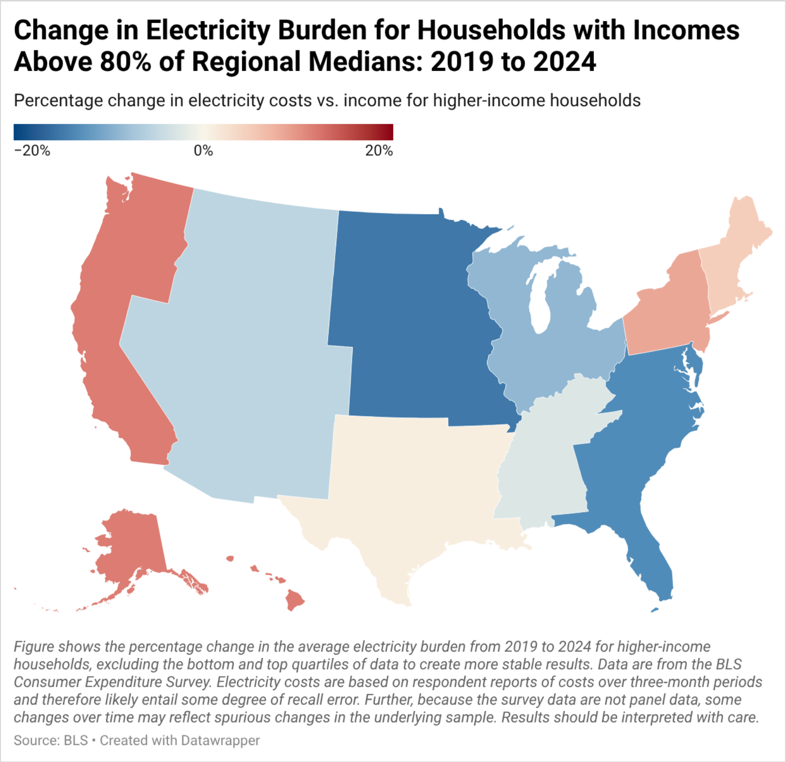
Regional electricity burdens from 2019 to 2024 improved in many regions but worsened in others, with some differences based on household income

From 2019 to 2024, regional electricity burdens (a contributor to energy burden) **increased the most** in the Pacific region (greatly impacted by California) and parts of the Mid-Atlantic region

LOWER INCOME



HIGHER INCOME



In New England, these data suggest worsening burdens for higher-income but improving burdens for lower-income households from 2019-2024; could be due to expansion of low-income bill assistance

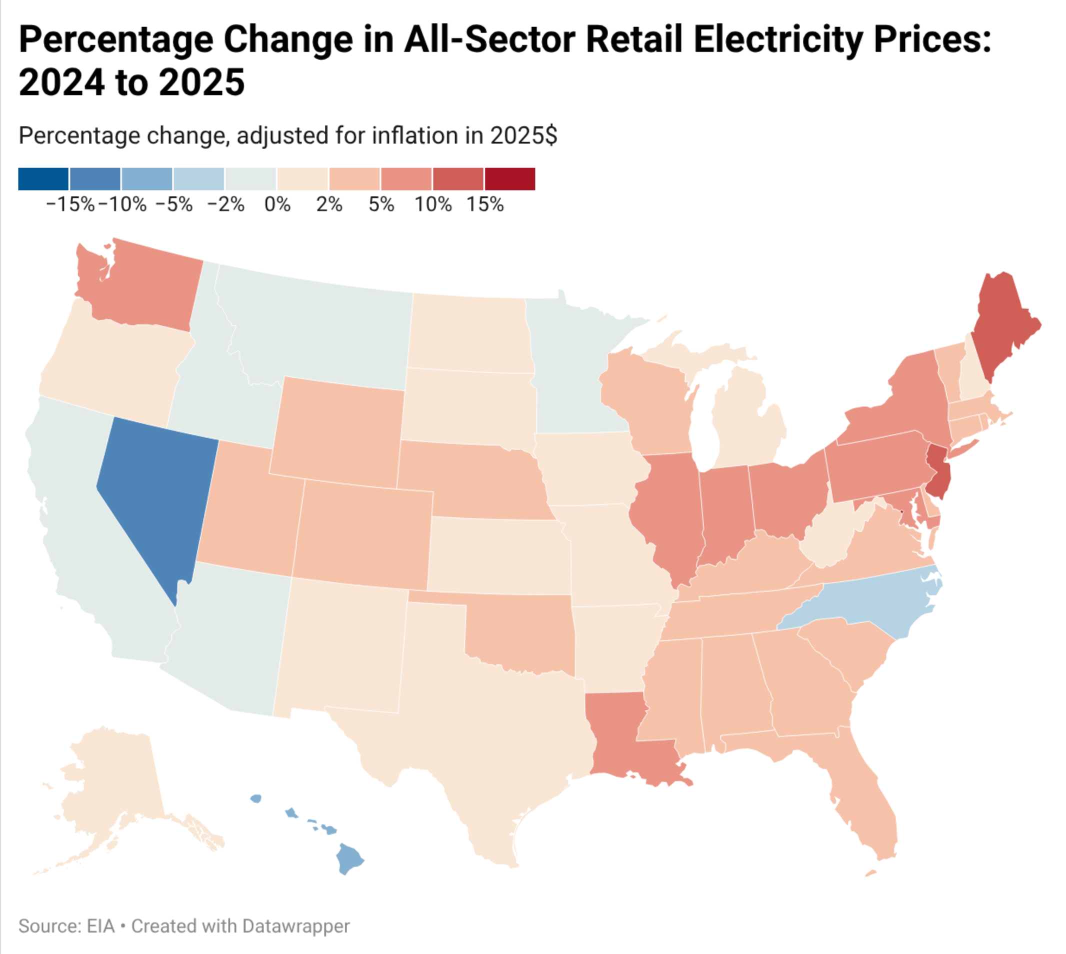
Maps show changes in regional average burden for households with incomes < 80% (left) and > 80% (right) of regional medians (state-level data not available)

Focused on electricity burden not broader concept of energy burden; based on BLS's "Consumer Expenditure Survey", with data available through 2024.

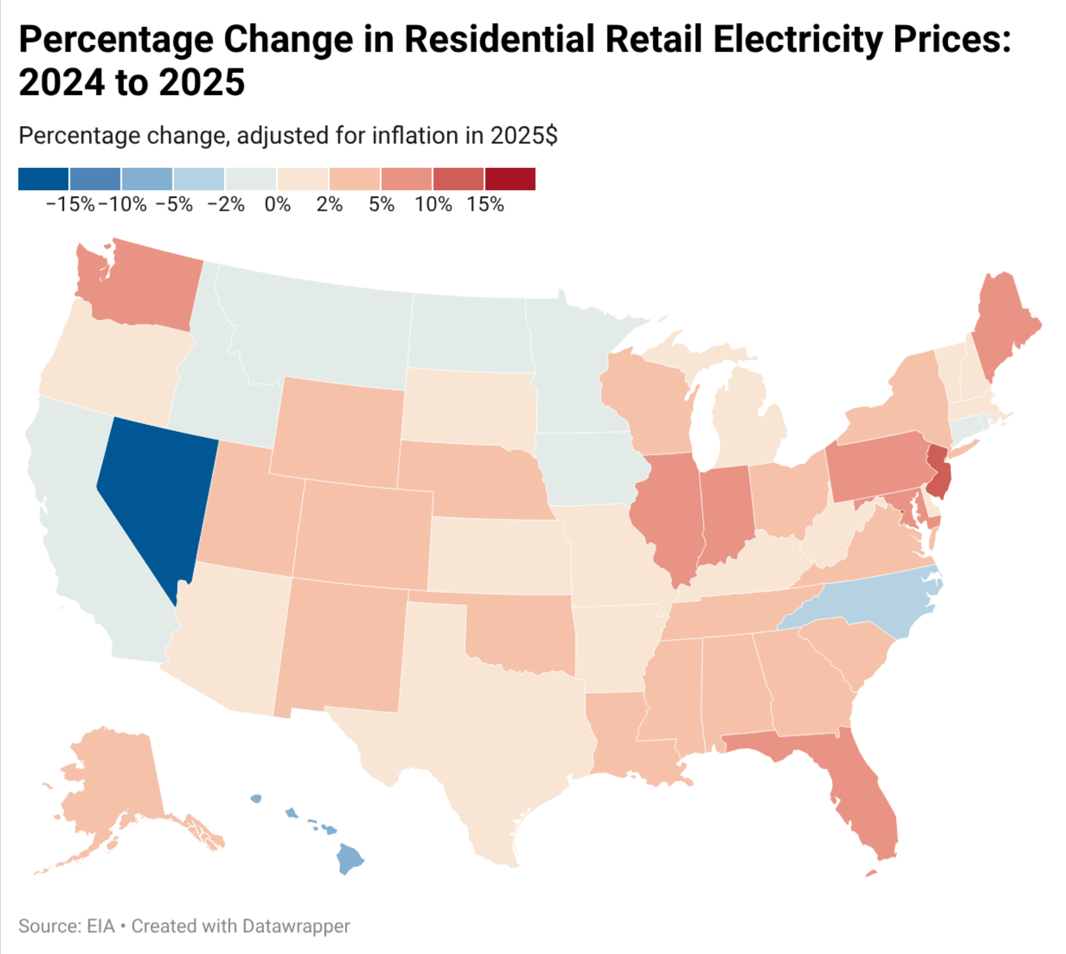
Drivers – *Understanding trends and variation over the last year … but within a longer-term context*

Retail price increases from 2024 to 2025 outpaced inflation in most states: percentage change in real, all-sector average *(left)* and residential *(right)*

ALL-SECTOR AVERAGE

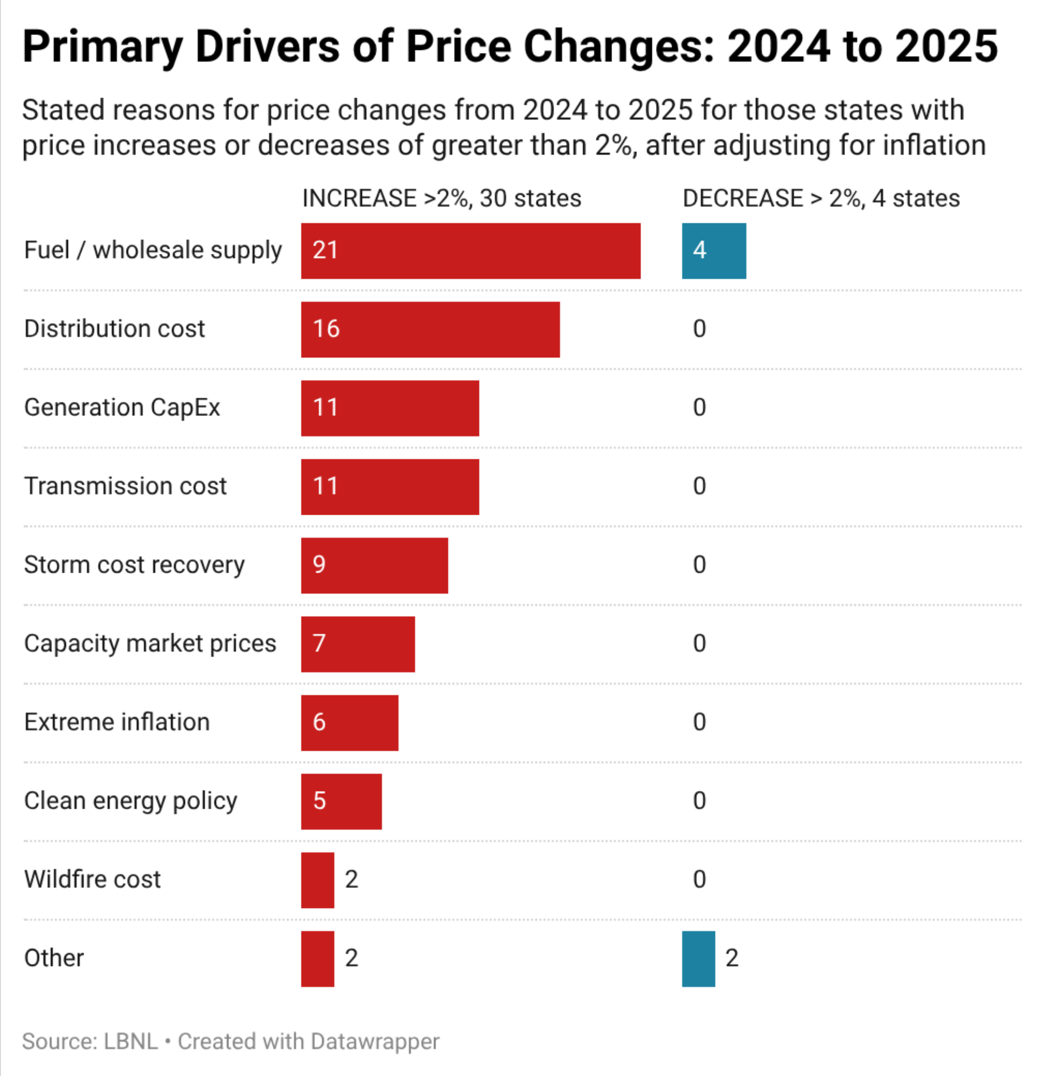


RESIDENTIAL



Primary YoY drivers: fuel & wholesale supply; distribution costs; cost of new generation; transmission costs; storm recovery; capacity prices

- Focused on states with larger inflation-adjusted price increases (>2%, 30 states) or decreases (>2%, 4 states)
- Reviewed filings, rate cases, tariffs, news, press releases, other analyses to broadly assess the primary drivers for year-over-year (YoY) all-sector average price changes
- Figure summarizes our assessment for states with **increases (red)** or **decreases (blue)**



The few states that experienced larger reductions in inflation-adjusted prices largely did so via lower fuel prices (sometimes from delayed reductions after previous increases at the onset of the Ukraine-Russia war)

Note: YoY trends are subject to various state ratemaking idiosyncrasies and will tend to emphasize certain drivers over others; drivers reported for individual states are likely to change in future years and vary if assessed over longer time periods

The availability of low-cost natural gas has historically placed downward pressure on generation costs, wholesale prices, and retail prices

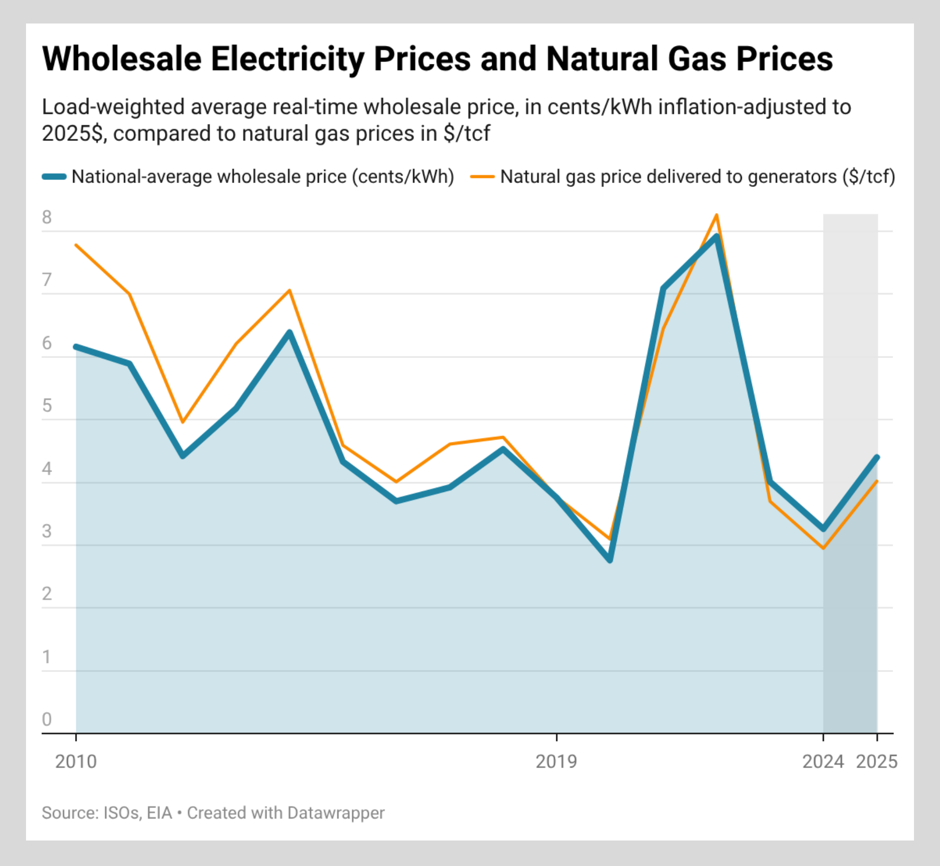
- Figure on left depicts EIA's 2010 projection for 2025 natural gas prices and generation shares, and contrasts those projections with actual 2025 data
  - *Key point:* Technological advances resulted in substantially lower natural gas prices than previously expected, leading to a dramatic rise in natural gas generation → reflecting its economic competitiveness
- Figure on right shows national-average load-weighted wholesale electricity prices in ISO regions over time
  - *Key point:* Wholesale prices track natural gas, with year-to-year volatility, but with **reductions** in inflation-adjusted terms

Comparing EIA Forecasts for 2025 with Actual Data

EIA forecast from 2010 Annual Energy Outlook

	Natural gas price for electric generators ($/tcf)	Natural gas share of total electric generation (%)
Forecast 2025	$9.4	18%
Actual 2025	$4.0	40%

Source: EIA • Created with Datawrapper



Fuel prices in 2025 increased from their 2024 lows, pushing wholesale power prices higher—and thereby also increasing retail prices in 2025

- In 2025, the national-average price of natural gas delivered to electric generators increased 36% from the all-time low in 2024, pushing generation costs and real-time wholesale electricity prices higher
- Among ISOs, wholesale price increases were greatest in ISO-NE (+2.9 ¢/kWh), NYISO (+2.7 ¢/kWh), PJM (+1.6 ¢/kWh), and MISO (+1.3 ¢/kWh) – in each case, closely tracking regional gas price increases
- ERCOT and SPP wholesale electricity prices also modestly rose; CAISO prices were flat
- The impact of gas price variability on retail electricity prices depends on: gas share of generation, pipeline constraints, fuel & power hedging practices, degree of participation in wholesale markets, and regulatory lags in how fuel & purchased power costs pass through to end-use consumers
- Nonetheless, increased gas prices and its impact on generation costs and wholesale prices was a driver of YoY changes in retail prices in **21 states**, especially in ISO-NE, NYISO, PJM, and MISO

Wholesale Prices and Impact of Fuel Costs: 2025 vs. 2024

Load-weighted average real-time wholesale price and price change in cents/kWh, inflation adjusted to 2025$, compared to year-over-year change in regional natural-gas hub prices

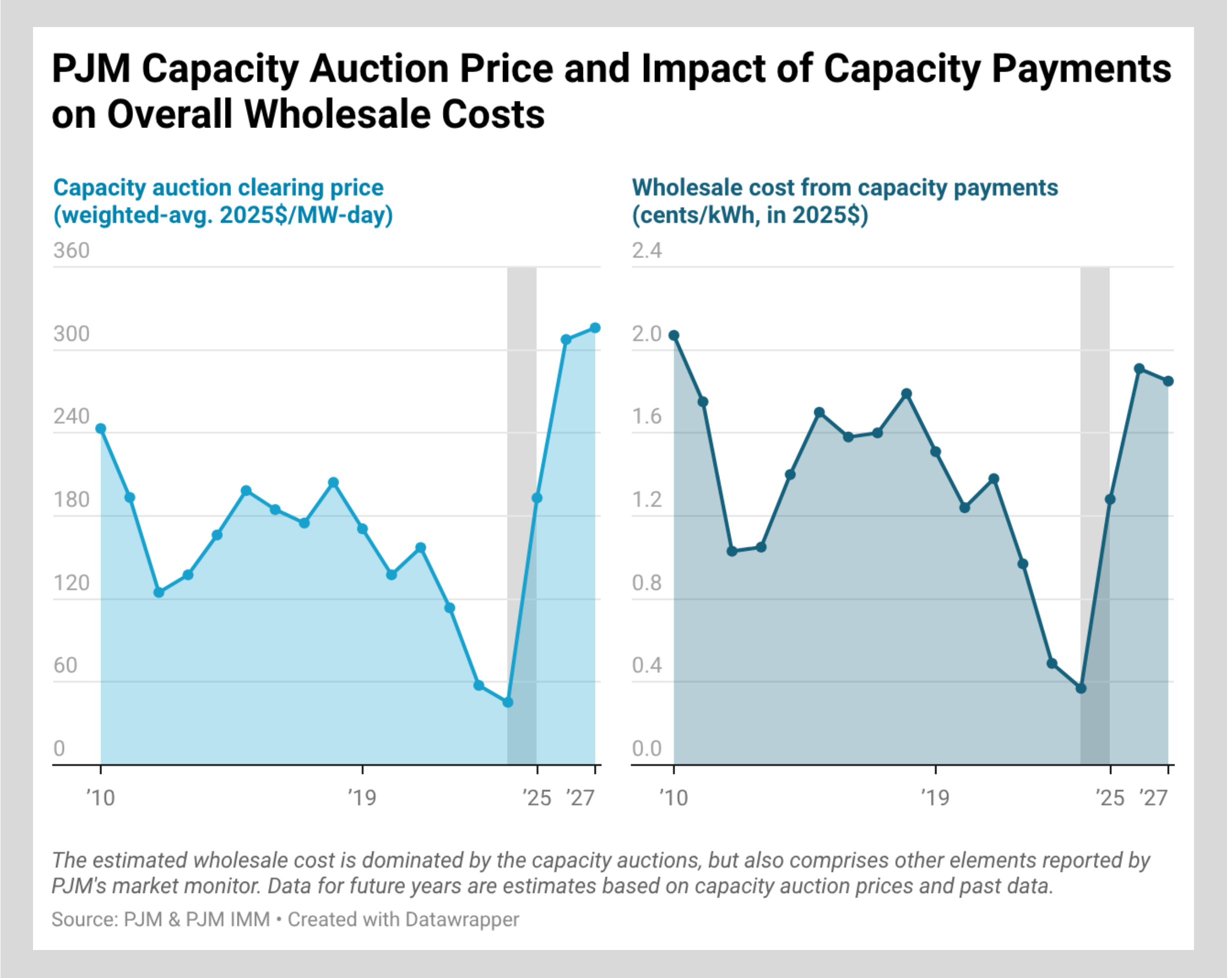
Region	2024: wholesale electricity price	2025: wholesale electricity price	Change in wholesale price (cents/kWh) ▼	Change in natural gas price ($/tcf)
ISO-NE	4.4	7.3	2.9	3.4
NYISO	3.9	6.6	2.7	3.1
PJM	3.5	5.1	1.6	1.6
MISO	3.0	4.3	1.3	1.1
ERCOT	3.0	3.3	0.4	1.2
SPP	2.6	2.9	0.3	1.2
CAISO	3.6	3.4	−0.1	0.7
National	3.3	4.4	1.2	1.1

Source: ISOs, EIA, Hitachi • Created with Datawrapper

Notes: Wholesale electricity prices are averages of hub prices. Natural gas prices are also regional hub prices, except that national prices are as delivered to electric generators.

Increases in capacity prices in the PJM region in 2025 were a significant contributor to the rise in YoY retail prices in many mid-Atlantic states

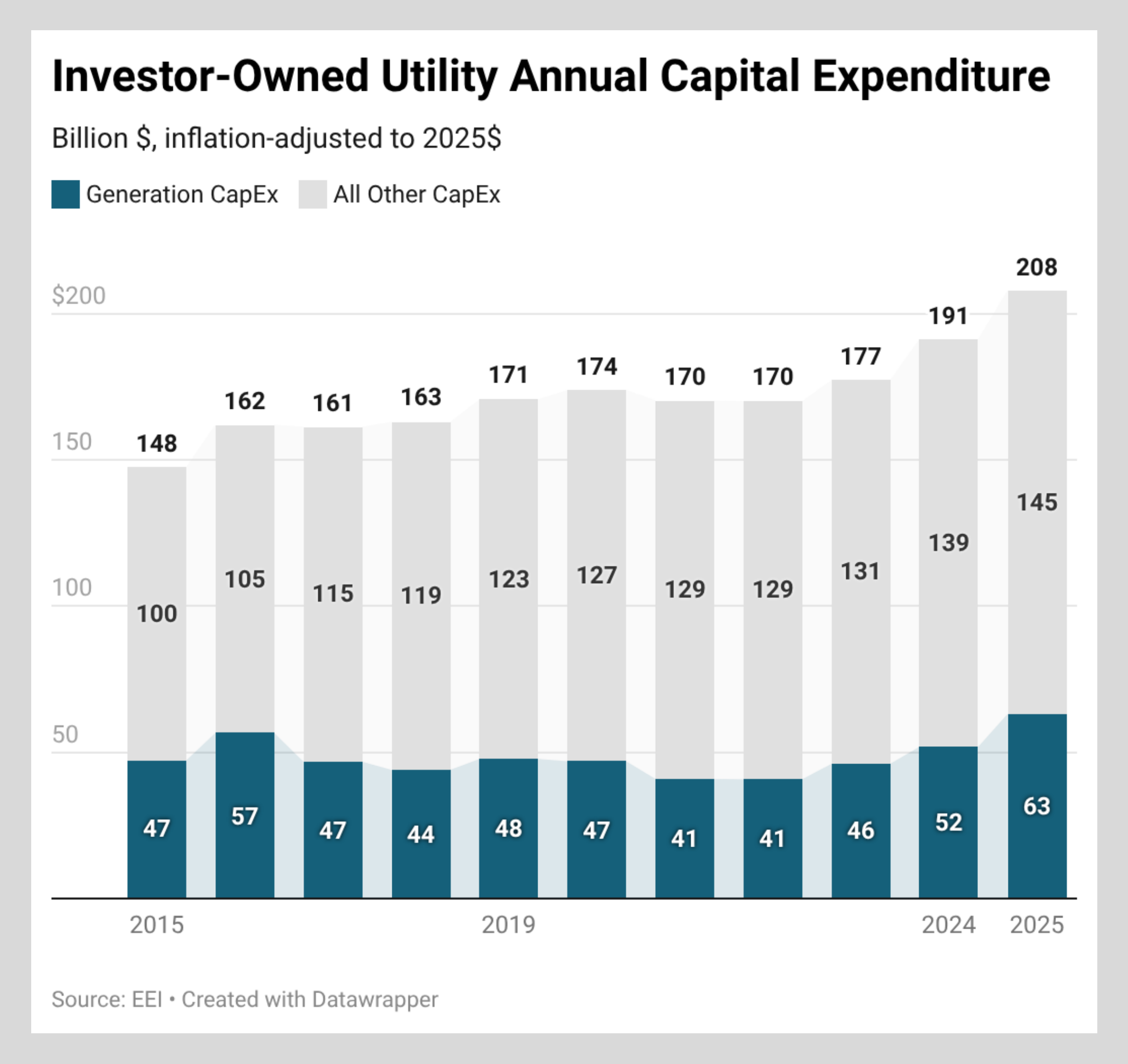
- Many PJM states saw large price increases in 2025 vs. 2024: DC (3.1 ¢/kWh), NJ (2.0), MD (1.5), IL (1.2), PA (1.2), IN (0.9), OH (0.8)
- In part, this is due to increases in PJM's capacity auction prices since their low in 2024 *(left figure)*
- Capacity costs drove average PJM wholesale costs up **0.9 ¢/kWh** in 2025 vs. 2024; an additional **0.6 ¢/kWh** impact is expected in 2026 *(right figure)*
- *Note on capacity markets: Utilities cannot always own their own generation in wholesale market regions. Capacity markets are additional to energy and ancillary service markets and are used to send supplemental price signals to generators that new supply is needed to meet electricity demand during periods of grid stress.*



Notes: (1) separate from capacity, wholesale energy costs increased **1.7 ¢/kWh** *from 2024 to 2025 as fuel prices rose; (2) the contribution of capacity payments to wholesale costs increased from its 2024 low, but did not greatly exceed earlier years and is comparable to some past experience in other ISOs (see later slide)*

Increased generation CapEx influenced the YoY change in retail prices in a variety of states, in part driven by anticipated load growth

- Annual investor-owned utility (IOU) generation CapEx increased **22% in 2025** in inflation-adjusted 2025$, after increasing **13% in both 2024 and 2023**
  - Following many years of flat CapEx spending
  - IOU CapEx is recovered over asset lifetimes, so price impacts are delayed, can grow w/ time
- Increased CapEx was driven by load growth, as well as supply-chain constraints and higher costs for most generation types
- CapEx impacted YoY prices in **11 states**, e.g.:
  - TN: TVA's 5.25% rate increase in late 2024 in part to fund construction of new generation
  - IN: Cost recovery for NIPSCO's investments in solar and storage resulted in a price increase
  - SC: Duke raised rates by 8.7% in late 2024 to cover cost of gas, nuclear, solar, and hydro



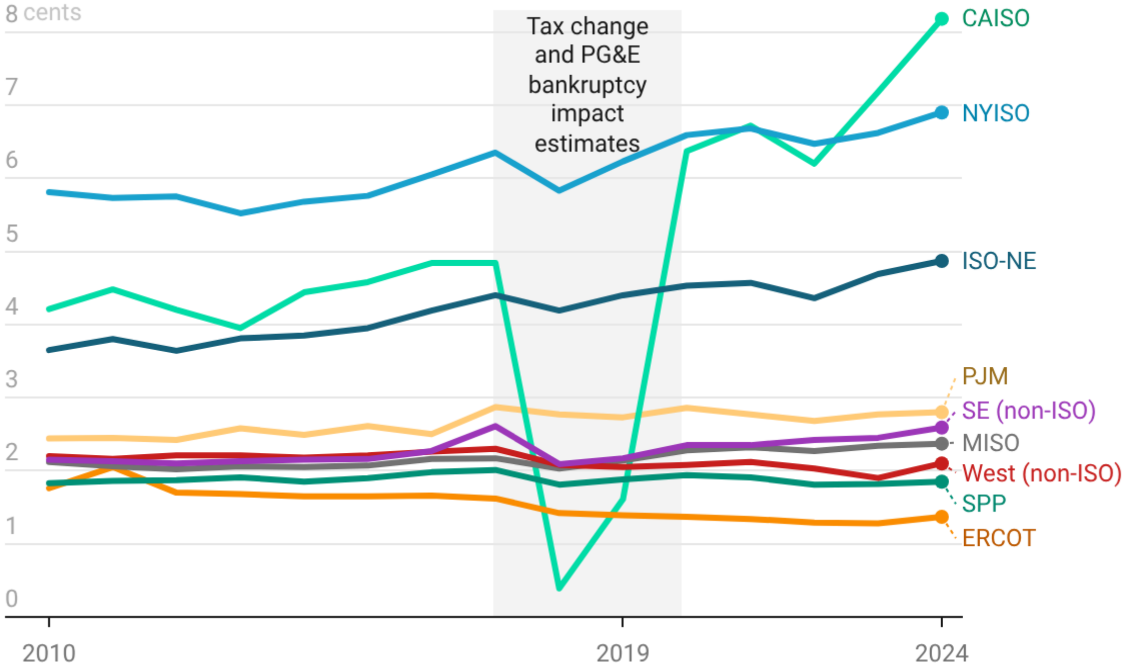
Note: Data prior to 2015 not available via latest EEI public data release

Distribution costs drove YoY retail prices higher in many states: age-based replacement at inflated prices, hardening, and storm cost recovery

- Our literature review ID'd **22 states** in which distribution costs increased retail prices from 2024 to 2025, some from storm recovery; e.g.:
  - Florida: 0.9-3.2 ¢/kWh temporary surcharge for storm cost recovery began in 2025 for 4 utilities
  - Central Maine Power: 2.5 ¢/kWh surcharge for storm cost recovery in 2025, up from 1.8 ¢/kWh in 2024
  - NYSEG: 0.9 ¢/kWh surcharge for securitized storm costs starting in 2025, to last up to 12 years
- California: Retail prices moderated in 2025 as wildfire mitigation costs declined for PG&E
- More broadly, the precise impact of distribution on YoY price changes is difficult to estimate consistently; the figure presents cost data from FERC, but data cannot be used to assess YoY price impacts and do not yet extend to 2025
- Focusing on the most-recent available years through 2024, cost growth was greatest in **CAISO, NYISO, ISO-NE; SE also climbing**

Estimated IOU Distribution Costs by Region: 2010-2024

Estimated average cost of distribution in cents/kWh, inflation adjusted to 2025$; data are rough estimates of broad cost trends not precise yearly price impacts

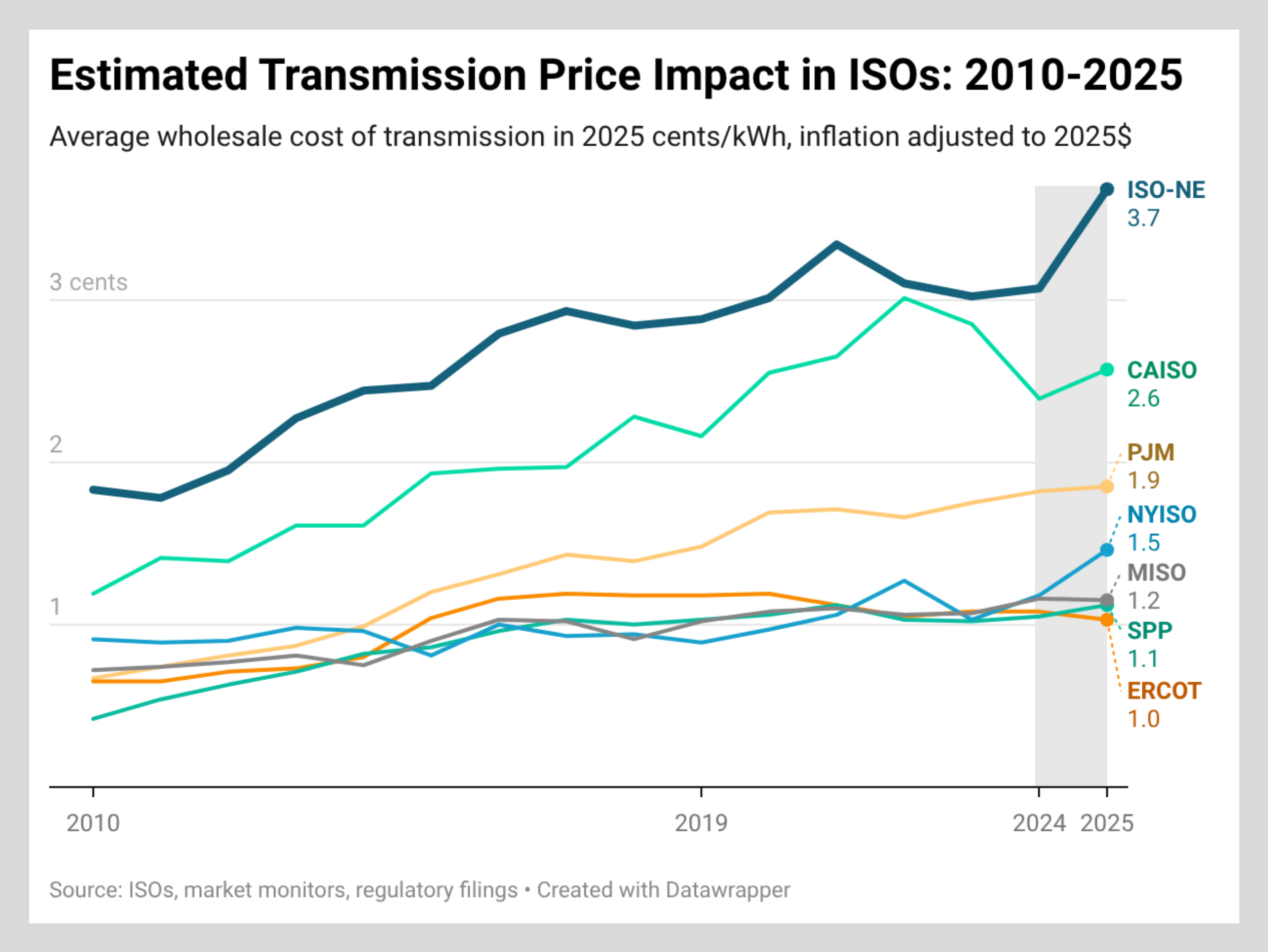


Data are rough estimates based on annually reported distribution O&M and depreciation combined with assumed allocations to distribution of taxes, interest, and shareholder net income. Actual customer price impacts will vary based on the vagaries of general rate cases, cost trackers, and other details.

Source: FERC Form 1 • Created with Datawrapper

FERC-approved transmission infrastructure costs in New England increased in 2025, pushing retail prices higher *(as did a change in ancillary services)*

- Many New England states saw retail price increases in 2025: ME (2.5 ¢/kWh), RI (0.9), MA (0.9), CT (0.5)
- One key reason is that transmission infrastructure costs substantially increased, up **0.6 ¢/kWh on average**
- Costs in ISO-NE increased in recent years due to reliability needs, aging infrastructure, and inflation; the increase in 2025 was also due to under-collection of previous costs
- Costs also increased in some other regions, but less so than ISO-NE
- *Note: ISO-NE made changes to its day-ahead* ***ancillary services*** *market in March 2025, via "Forecast Energy Requirement" credits. According to the market monitor, this resulted in additional costs of ~0.5 ¢/kWh in 2025.*



Note: ISO-NE data shown in figure are dominated by trends in regional network service (transmission OpEx and CapEx paid for by all customers in ISO-NE, given the shared nature of the assets) but also include estimates of local network service (smaller lines, the OpEx and CapEx of which vary by utility).

Some additional states experienced notable or interesting retail price changes—for a diversity of previously stated and additional reasons

Price Increase

Maine	**Transmission:** Significant YoY increase in regional transmission costs
	Storm cost recovery: Increase in cost recovery from storm damage in 2024
	Net billing: Growth in community solar with attractive net billing compensation
	Natural gas: Increased wholesale power prices in 2025 due largely to rise in gas prices
Tennessee	**New generation:** Investments needed due to significant load growth
	Nuclear outage: Prolonged outage led to more expensive natural gas
	Distribution: Distribution system repairs and inflation in equipment costs

Price Decrease

Nevada	**Natural gas:** High-cost gas from previous years began rolling off bills
Hawaii	**Fuel oil:** Updated supply contracts reflecting lower global oil prices
N. Carolina	**Natural gas:** Reduction in fuel surcharges after annual review
	Nuclear tax credits: New federal credits for existing nuclear lowered prices

LAWRENCE BERKELEY NATIONAL LABORATORY

Medium-term relationships – *2019 to 2025*

Differences in average retail prices and changes to those prices over time can be impacted by many general and some state-specific factors

- Mix of sources of supply: gas, coal, oil, nuclear, hydropower, wind, solar, storage, etc.
- Local natural resource quality and delivery (pipeline, transmission) constraints
- Relative cost of building new infrastructure given labor costs and other regional dynamics
- Characteristics of customer load: quantity, growth, load factor, flexibility, etc.
- Balance of supply and demand: is the market tight or oversupplied
- Age of existing assets and relative need for replacement
- Investments in grid modernization: technology and resilience
- Impact of natural disasters, extreme weather, wildfires
- Policy & planning: RPS, EE, DER, low-income assistance, cap-and-trade, nuclear, etc.
- Health and environmental regulations that impact plant retirement and costs
- Utility ownership structure: public- vs. investor- owned
- Presence and design of wholesale competitive market
- Presence and nature of retail electricity competition
- Degree of vertical integration (generation ownership) among utilities
- Service territory size, geography, population, and other characteristics

This Section Focuses More Holistically on Relationships from 2019 to 2025

The slides that follow focus on a subset of factors that may have influenced state-level price changes since 2019. This section emphasizes 2019-2025 to span COVID and the period in which nominal prices spiked. The analysis does not assess all possible factors but includes many of the most-likely candidates. Factors include those listed in the previous YoY section (here focused on 2019-2025 data) and additional ones that influenced longer-term trends:

- Distribution and transmission costs, as impacted by age-based replacement, hardening, expansion, supply-chain constraints, storm cost recovery, and wildfire mitigation
- State renewables portfolio standards, net energy metering, and carbon cap-and-trade programs
- Generation and fuels, including utility-scale wind and solar (outside of state requirements), natural gas, coal, and nuclear
- Organized capacity markets and related prices
- Utility ownership, financing, and other differences

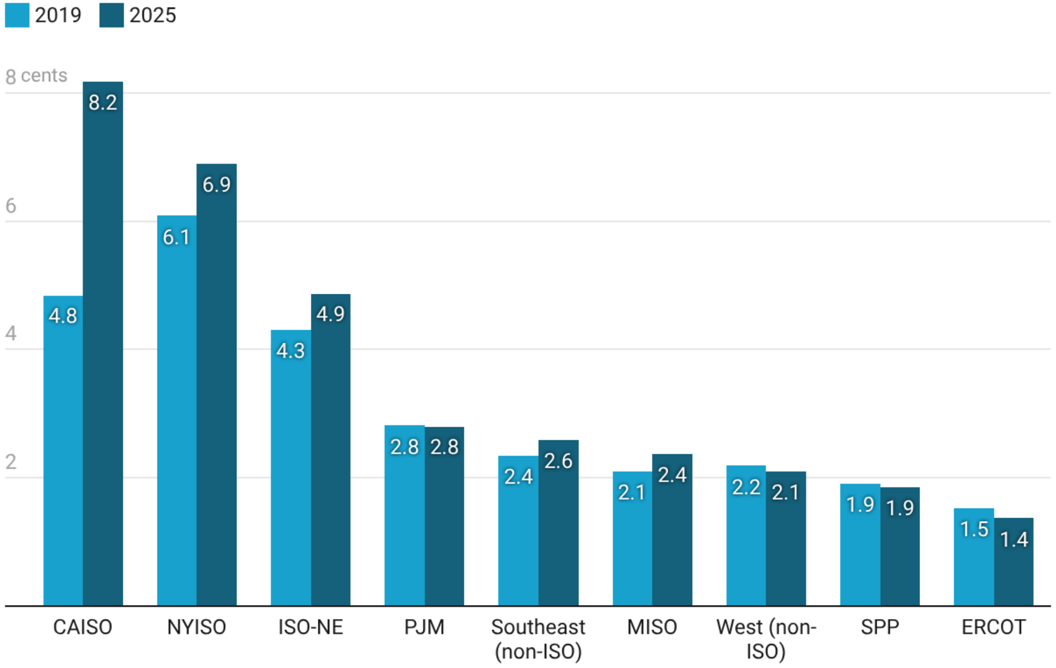
Load growth is separately covered in the following section

Distribution expenditures contributed to IOU retail price increases from 2019 to 2025, especially in California, New York, and New England

- Total IOU distribution spending grew at an avg. 5%/year from 2019 to 2025 (in real$), increasing retail prices in some regions
- The impact of distribution costs on prices is difficult to estimate consistently; figure estimates average price impact from 2019 to 2025 across all customers (***note:*** *actual impacts will be greater for smaller customers who, in practice, bear most of these costs)*
- Average price impacts span a wide range: **highest distribution-related prices and price increases in CAISO, NYISO, ISO-NE**
  - CAISO prices impacted by wildfire mitigation
  - All three regions impacted by reductions in retail sales, magnifying impact of cost increases on prices
- Estimated distribution price impacts are lower and changed less in all other regions

Estimated Distribution Price Impacts: 2019 to 2025

Rough estimate of average price impact of distribution in cents/kWh, inflation adjusted to 2025$

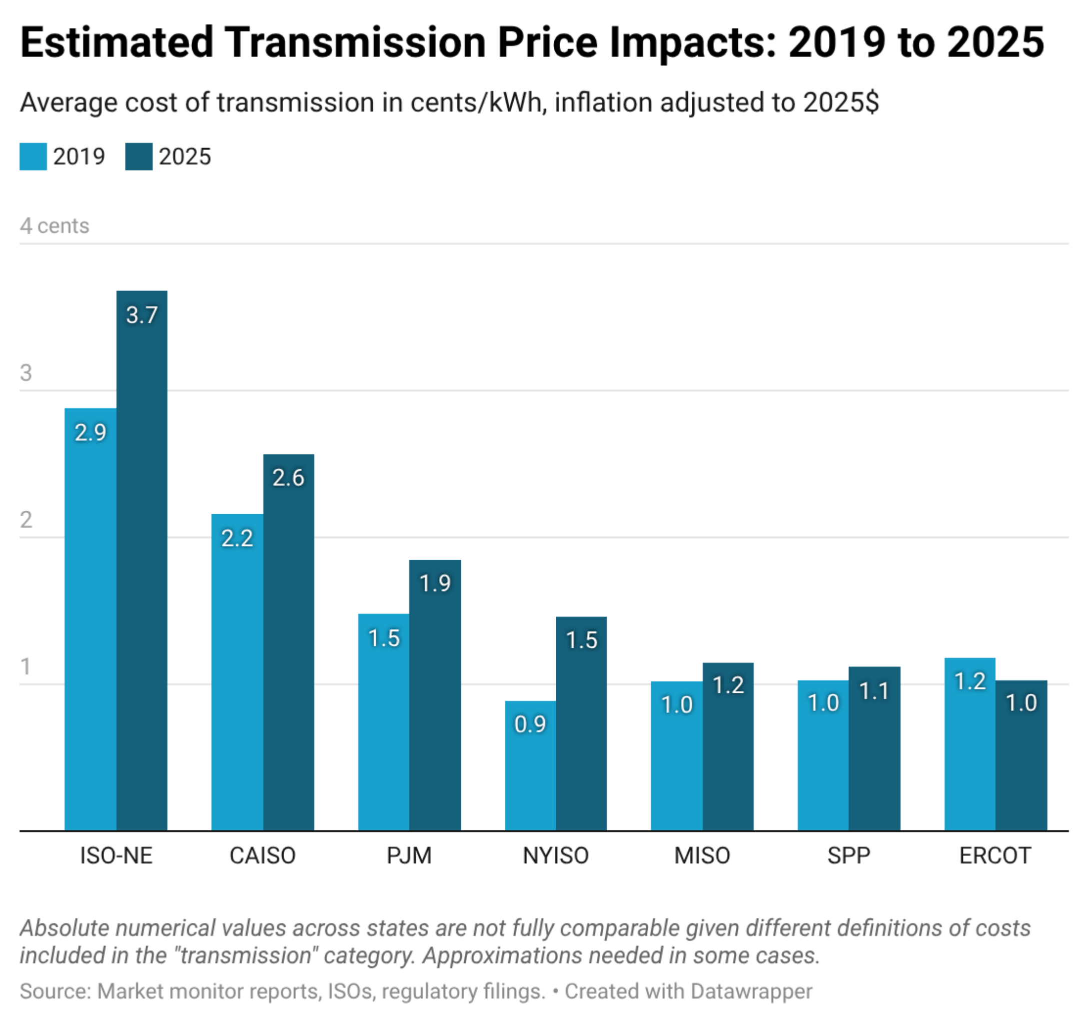


Data are rough estimates based on annually reported distribution O&M and depreciation combined with assumed allocations to distribution of taxes, interest, and shareholder net income. Actual customer price impacts will vary based on the vagaries of general rate cases, cost trackers, and other details. To approximate price impacts, we assume a 1-year lag between cost incidence and prices, and further adjust lag assumptions based on tax policy changes in late 2017 and PG&E's bankruptcy in 2019. As a result, 2025 estimates are based on recorded costs in 2024, while 2019 estimates are based on average costs from 2017-2018 for all regions except CAISO, which uses 2017 cost data to approximate 2019 prices.

Source: FERC Form 1 • Created with Datawrapper

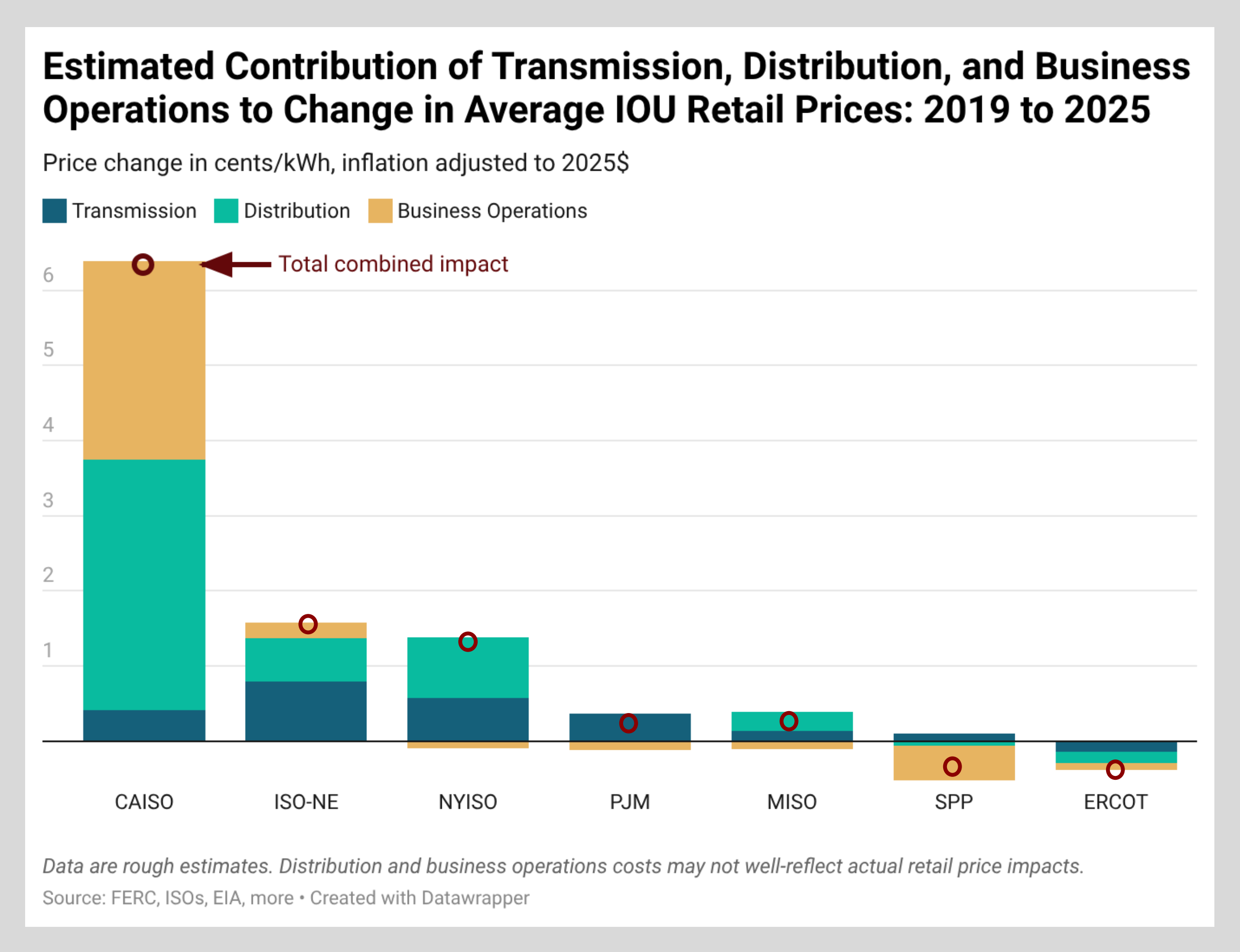
Transmission expenditures contributed to retail electricity price increases from 2019 to 2025, especially in New England, New York, California & PJM

- Transmission costs are highest & increased the most in **ISO-NE, up 0.8 ¢/kWh from 2019 to 2025 after adjusting for inflation**
  - Driven primarily by reliability needs, replacement of aging infrastructure, and higher equipment costs
- Costs also increased significantly in NYISO (0.6 ¢/kWh), and CAISO & PJM (0.4 ¢/kWh)
  - Same drivers, but also variously impacted by policy desire to connect new renewable sources
- Transmission costs are generally lower and changed less in ERCOT, MISO, and SPP
- Transmission costs reported here include ISO-planned investments as well as those planned by local utilities with little ISO role; see earlier slide for data back to 2010
- Note: **higher transmission costs can lower retail prices** ***if*** used to reduce supply costs



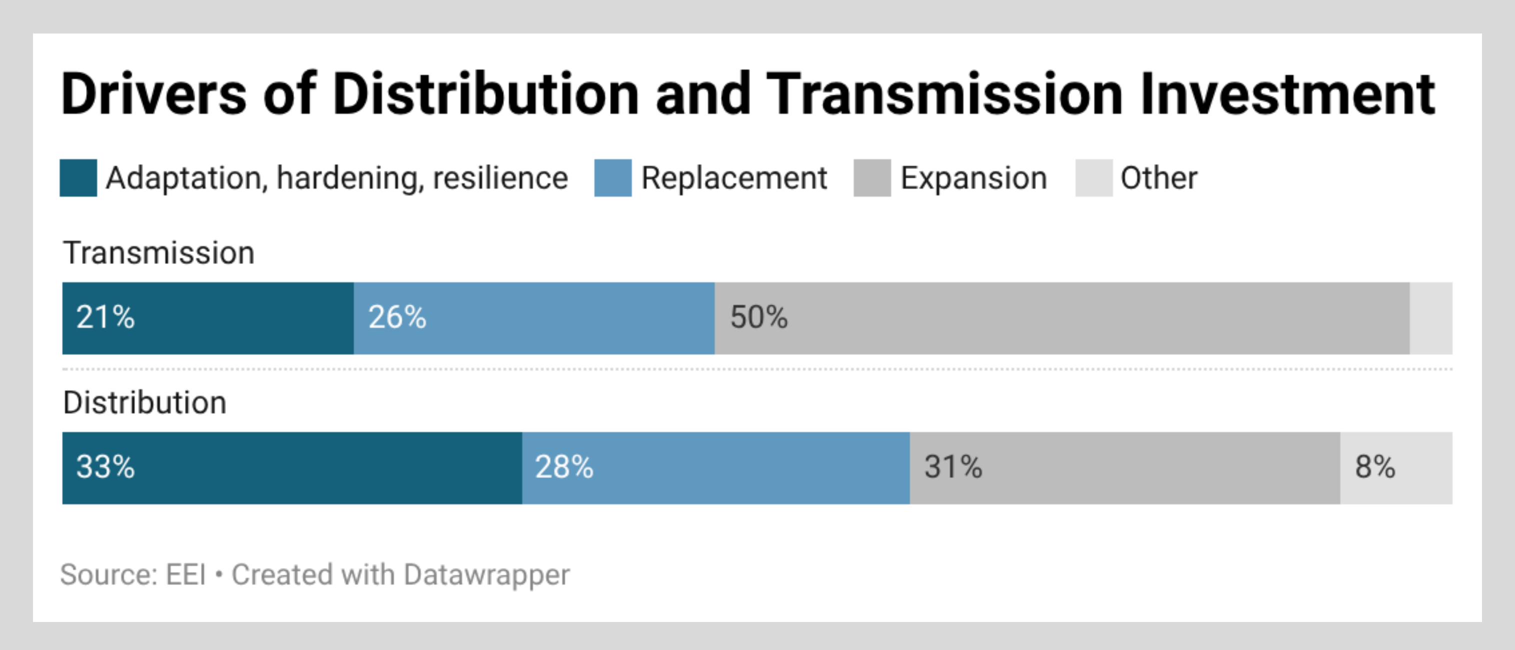
Transmission, distribution, and business operations costs helped drive inflation-adjusted price increases in regions with the largest rise in prices

- The figure shows estimates of the combined role of transmission, distribution, and business operations in increasing average inflation-adjusted IOU prices from 2019 to 2025 in ISO regions
  - Business operations costs come from FERC Form 1, and include expenses related to: customer accounts; customer service and informational; sales; administrative and general
  - Distribution and business operations estimates should be considered rough approximations, given the complexities of estimating retail price impacts from FERC Form 1 cost data
- Despite limitations, combined impact of these three drivers was especially significant in CAISO, ISO-NE, NYISO
- Wildfire costs in CA are included in the distribution (e.g., vegetation management) & business operations (e.g., liability insurance) categories



Recent distribution and transmission investments have been driven by replacement and hardening, though with growing emphasis on expansion

- Grid infrastructure is aging—T&D assets were often built more than 50 years ago and, over time, need to be replaced and modernized
  - Example: Brattle estimates >$10 billion/year annually for replacement of aging transmission assets[1]
- **EEI companies** reported in 2025 that **61% of distribution** & **47% of transmission** investment was driven by "**replacement**" or "**adaptation, hardening, and resilience**" initiatives[2]
- "**Expansion**" was **50% of transmission** investment in the 2025 survey, up from 42% in the 2024 survey[2]
- Relying on a different data source and method, FERC reports 31% of transmission line-miles built in 2025 were designed for reliability needs, 28% for aging infrastructure, and 18% for load growth[3]



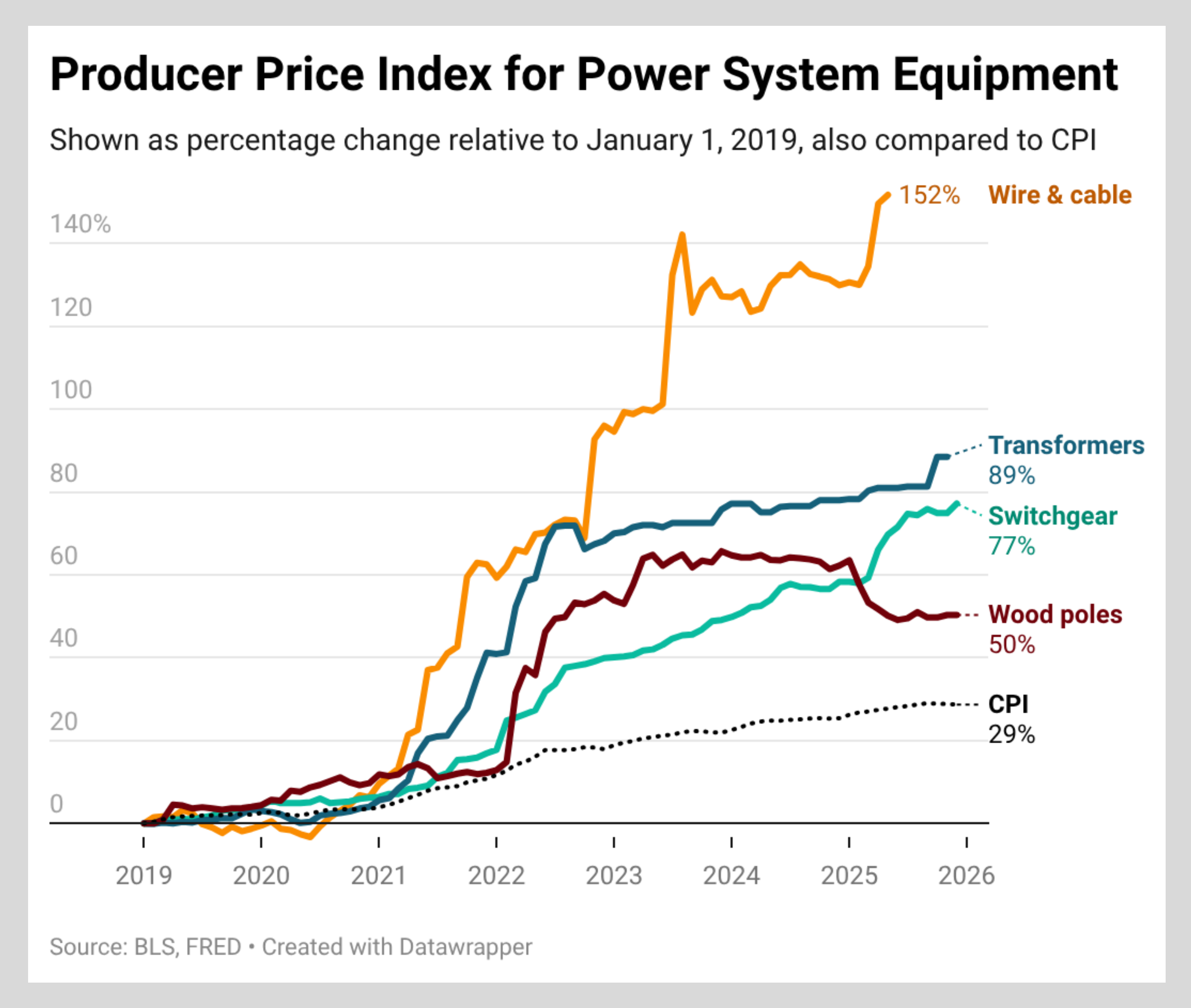
[1] Brattle (2025), [2] EEI (2025), [3] FERC (2026)

One of the reasons for growth in distribution and transmission costs is that equipment prices have grown well-above the pace of inflation

- Regardless of the driver, supply-chain constraints and the resulting elevated equipment prices have contributed to the overall impacts of T&D in increasing retail prices

- The figure shows producer price indices for various equipment important to T&D, contrasting those price increases with the economy-wide CPI

- Price indices for some T&D equipment have moderated somewhat in recent years, but price increases since 2019 remain well above the CPI



Storm recovery and wildfire mitigation also impacted distribution (and transmission) costs, significantly increasing retail prices in some states

Storms result in **reactive** investments: needed repairs following damage; **>1 ¢/kWh** impact for some East & Gulf coast states

Recent Estimates of Utility Storm Recovery Price Impacts

Utility	State	Year	Duration	Price Impact (¢/kWh)
Duke Energy Florida	FL	2025	1-year	3.2
Central Maine Power	ME	2025	2-years	2.5
Tampa Electric Company	FL	2025	1.5-years	2.0
Entergy Louisiana	LA	2025	15-years	1.4
Florida Power & Light	FL	2025	1-year	1.2
Central Florida Electric Coop.	FL	2025	temporary	0.9
NYSEG	NY	2025	6-12 years	0.9
SWEPCO	LA	2025	14-years	0.7
Eversource	CT	proposed	15-years	0.6
Duke Energy Progress	SC	2025	20-years	0.6
CLECO	LA	2022	9-20 years	0.5
Oncor	TX	proposed	long-term	0.5
Georgia Power	GA	proposed	4-years	0.4
National Grid	MA	2025	5-years	0.4
Duke Energy Progress	NC	2025	20-years	0.4
Green Mountain Power	VT	2025	1-year	0.4
Centerpoint	TX	2025	15-years	0.3
Entergy Texas	TX	2022	15-years	0.2
Rochester Gas & Electric	NY	2025	10-years	0.2
Duke Energy Carolinas	NC	2025	20-years	0.2
PPL Electric	PA	2025	1-year	0.2
PSE&G	NJ	2025	long-term	0.2
AEP Texas	TX	2019	5-15 years	0.1
Portland General Electric	OR	2023	7-years	0.1

Source: LBNL • Created with Datawrapper

Includes estimates for a subset of utilities. Estimates represent actual or likely impact on (mostly) residential prices in year shown. Some cost recovery mechanisms are short duration whereas in other cases costs are securitized and price impacts will persist for as many as 20+ years. Data are imperfect and should only be used to illustrate wide range of and significant impacts.

Sources: Review of regulatory filings and tariffs, for subset of utilities

Wildfires (& storms) motivate **proactive** action to reduce damage; **> 4 ¢/kWh** price impact in CA, growing throughout West

Recent Estimates of Utility Wildfire Mitigation Costs

Utility	State	Equivalent Impact (¢/kWh)	Scope
PG&E	CA	5.0	actual price: mitigation & liability
SDG&E	CA	4.7	actual price: mitigation & liability
SCE	CA	3.3	actual price: mitigation & liability
KIUC	HI	1.7	proposed cost: mitigation
Hawaii Electric	HI	1.5	proposed cost: mitigation
PSCo	CO	1.5	estimated price: mitigation
Rocky Mountain Power	UT	0.7	proposed cost: mitigation
PGE	OR	0.6	actual price: mitigation
Rocky Mountain Power	WY	0.6	actual price: mitigation & liability
Idaho Power	ID	0.4	proposed cost: mitigation
Pacific Power	OR	0.4	actual price: mitigation
Northwestern	MT	0.4	estimated price: mitigation
APS	AZ	0.3	actual cost: mitigation
Nevada Power-North	NV	0.3	actual price: mitigation
AEP Texas	TX	0.3	actual cost: mitigation
Avista	WA	0.2	actual price: mitigation
Oncor	TX	0.2	actual cost: mitigation
PNM	NM	0.1	actual price: mitigation & liability
PSE	WA	0.1	actual price: mitigation & liability
SPS	TX	0.1	actual cost: mitigation
Nevada Power-South	NV	0.0	actual price: mitigation

Source: LBNL • Created with Datawrapper

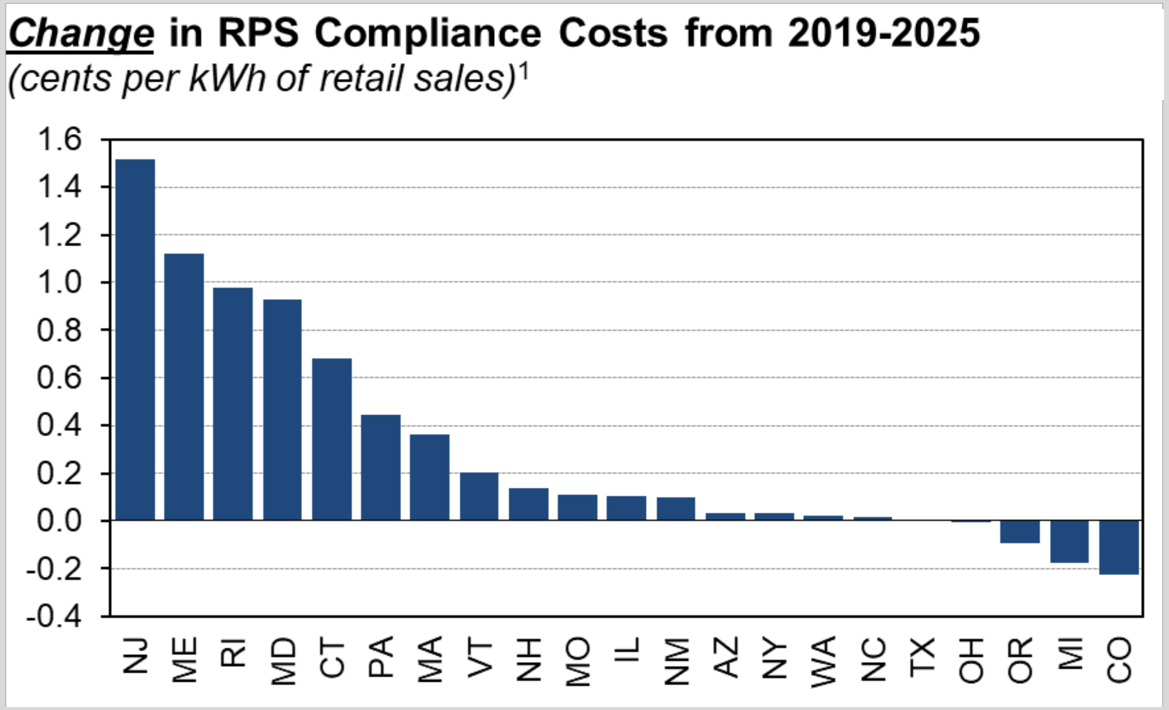
Includes recent (2025) or projected (2026-2028) estimates for subset of utilities, some actual and some proposed. Data are not fully comparable: sometimes includes price impacts, other times total costs normalized by sales. Most only cover mitigation costs, but some also include liability insurance. Data should only be used to illustrate wide range of and significant impacts.

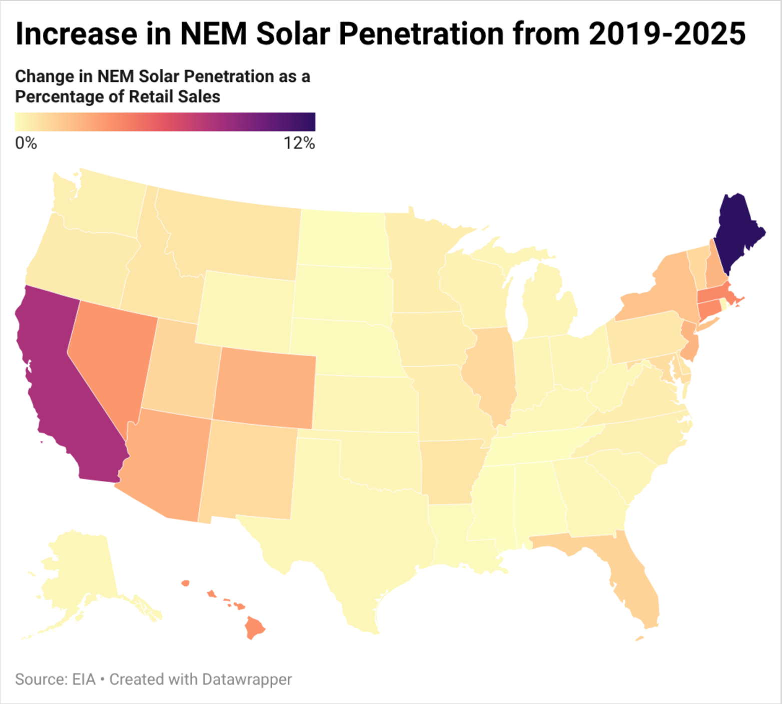
Sources: Review of regulatory filings and tariffs, for subset of utilities

State policies to require or encourage wind and solar deployment above what the competitive market would deliver have often increased prices

- **RPS:** Recent wind and solar growth that contributed to incremental state RPS demand often increased prices
- RPS compliance costs from 2019 to 2025 equate to an average price increase of ~0.3 ¢/kWh; in some mid-Atlantic and New England states ≥1 ¢/kWh[1]; earlier statistical analysis supports impacts of this magnitude

- **Net metering:** Benefits adopters, but can result in fixed costs being spread over lower sales, leading to higher prices[2]
- Effects variable; statistical analysis and other studies suggest impacts <0.5 ¢/kWh in ~40 states, but as high as >2 ¢/kWh in CA



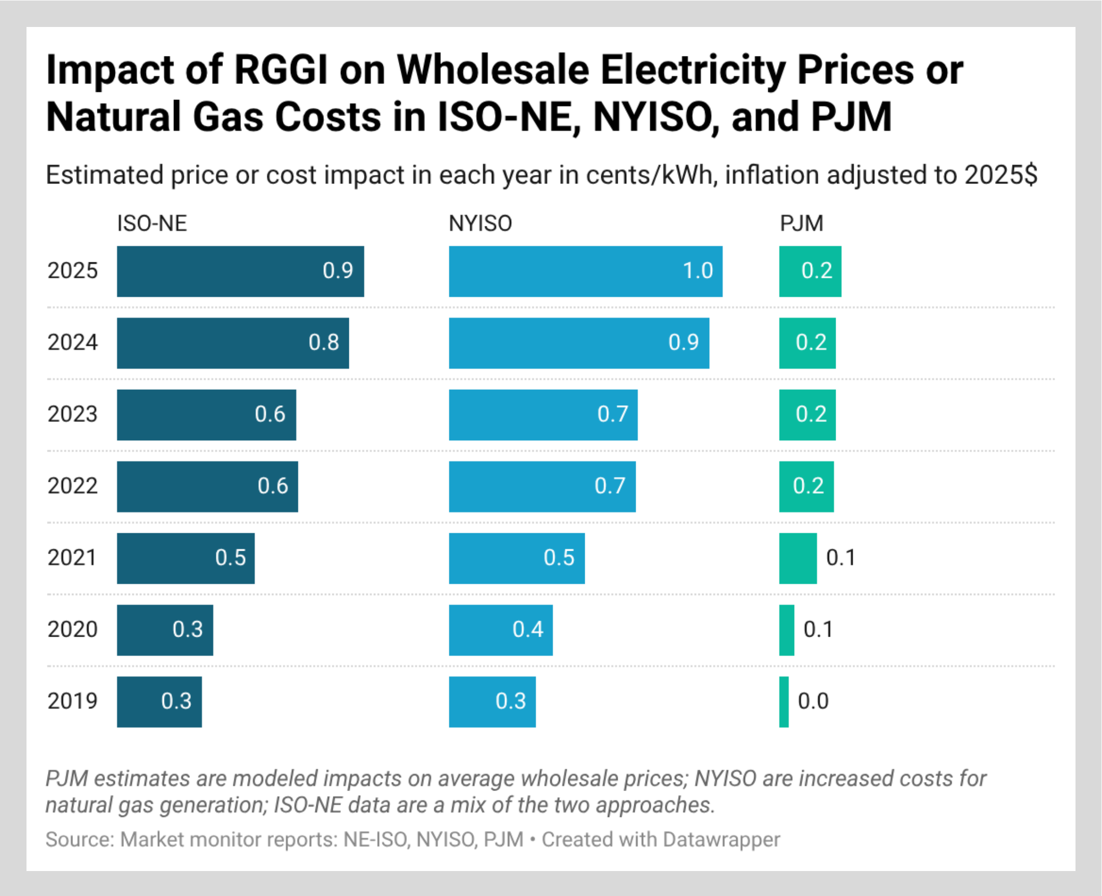


Sources: [1] Barbose (2024)

Sources: [2] National Academies (2023), Sieren-Smith et al. (2024), O'Shaughnessy et al. (2025)

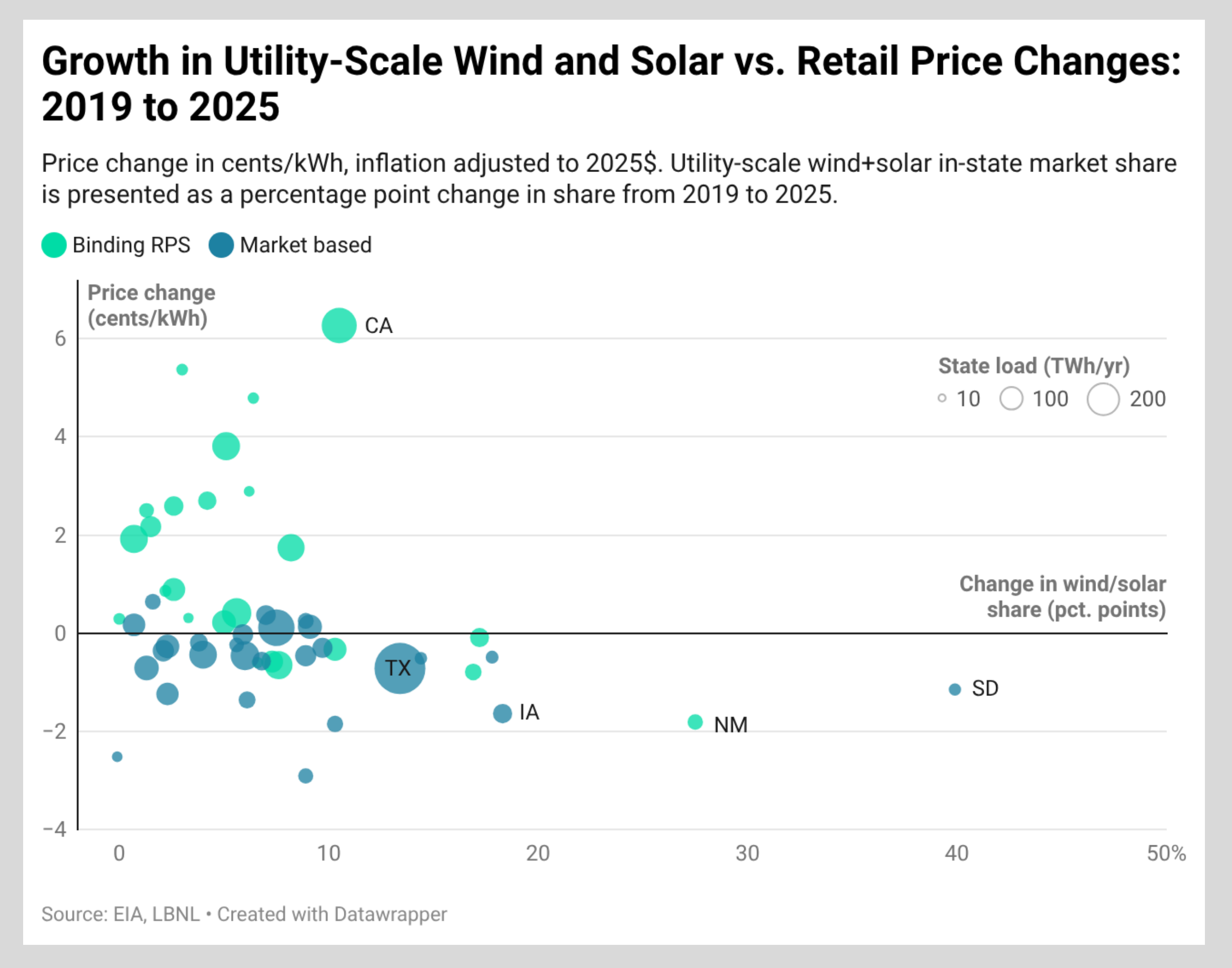
Carbon cap-and-trade programs have increased retail prices in some states, though recycling of auction revenue reduces customer impacts

- Carbon prices in the Regional Greenhouse Gas Initiative (RGGI) have risen since 2019, increasing wholesale prices from 2019 to 2025 by **> 0.5 ¢/kWh** in New England & New York
- Impacts on average retail prices are hard to estimate, but will generally be lower than wholesale impacts for two primary reasons:
  - Generation is not all purchased in the wholesale market or from carbon-producing generators
  - Auction revenue is, in part, re-invested in customer efficiency and bill discounts, reducing bill impacts
- California and Washington have similar programs, with even-higher absolute allowance prices:
  - CA: Change in allowance prices from 2019 to 2025 increased natural gas costs from ~ 0.9 to 1.3 ¢/kWh
  - WA: Change in allowance prices from 2019 to 2025 increased natural gas costs from ~ 0 to 2.5 ¢/kWh
  - Customer bill credits and large amounts of low-emitting resources moderate impacts in both states, but there is evidence of recent price impacts in Washington; in CA, residential bill credits appear to have offset price impact



State policies often increased prices but “market based” wind and solar, supported by tax incentives, do not appear to have driven price increases

- States with binding RPS’s often experienced increased prices, as shown on earlier slide and as illustrated in the figure to the right
- Most growth in utility-scale wind and solar occurred outside of RPS policies, supported by tax incentives but not compelled by RPS programs (termed “market based” here)
- There is no obvious correlation between higher price increases and “market based” deployment of wind and solar over this period
- Earlier statistical analysis supports these graphical relationships: binding RPS generally increased prices, especially in many New England and Mid-Atlantic states; “market based” wind and solar do not appear to have increased prices in recent years



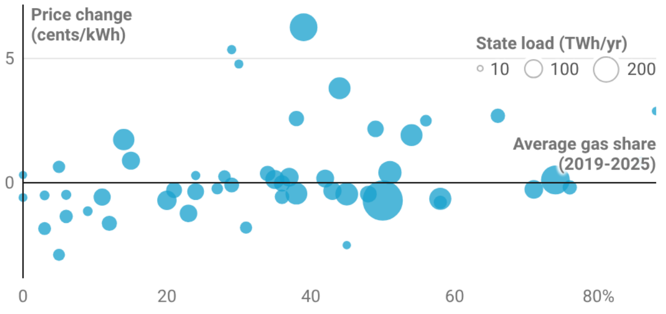
Simple bubble graphic should be interpreted with care (here and on next slides) because price changes were driven by multiple factors and due to correlated effects; earlier statistical analysis was used to isolate drivers, and produced results consistent with general observed trends

Low-cost natural gas reduced retail prices over the long term; gas price fluctuations impacted year-to-year variation in retail prices over 2019-2025

- Declining inflation-adjusted gas prices contributed to reductions in generation costs over the long term, putting downward pressure on electricity prices—as shown on earlier slide
- Inflation-adjusted gas prices were slightly higher in 2025 than 2019, driving up wholesale prices, though natural gas's share of state generation does not have a strong relationship with retail price changes over the 2019 to 2025 period *(upper figure)*
- Between 2019 and 2025, natural gas prices were impacted by the shock of the Ukraine-Russia war, creating an increase and subsequent decrease in retail electricity prices in many states
  - Some experienced increased retail prices of 2 ¢/kWh or even > 4 ¢/kWh through 2022-2023, but with a subsequent decline after the shock passed
- Natural gas prices also rose in 2025 relative to their all-time lows in 2024, as described previously, impacting retail prices
- Lower chart shows, generally, how year-to-year retail electricity price variability from 2019-2025 was impacted by a state's average natural gas share over the same time frame

Average Gas Share vs. Retail Price Changes: 2019 to 2025

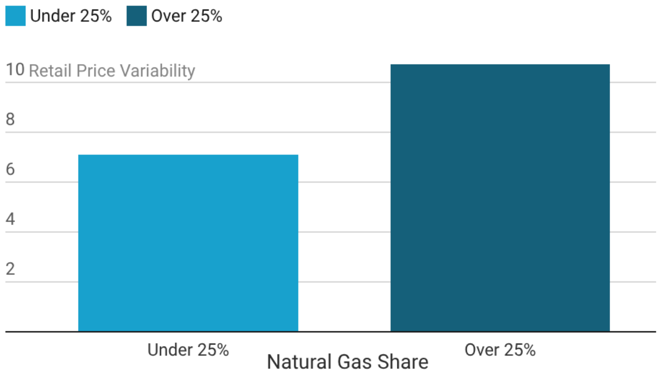
Price change in cents/kWh, inflation adjusted to 2025$. Gas market share is in-state gas share of generation from 2019 to 2025.



Source: EIA, LBNL • Created with Datawrapper

Natural Gas Share vs. Retail Price Variability: 2019-2025

Retail price variability = state-average coefficient of variation of annual prices. Gas share = avg. state share of total generation from 2019-2025.



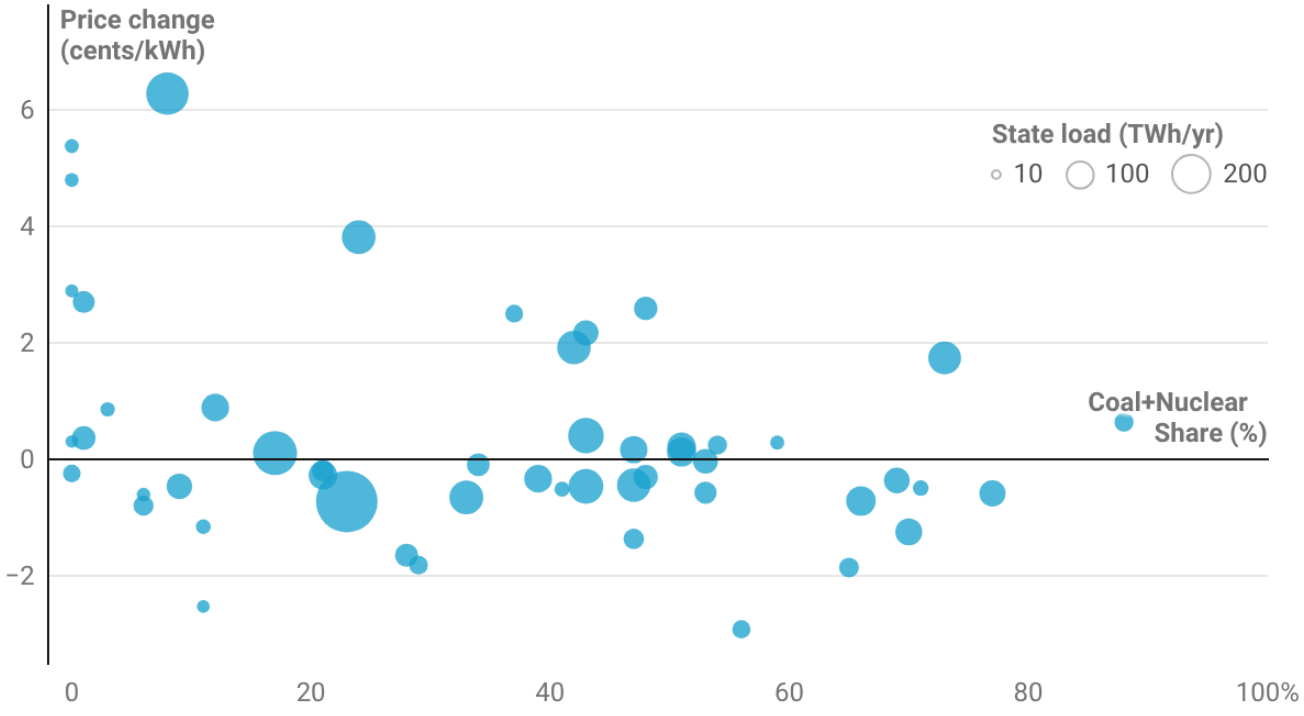
Source: EIA • Created with Datawrapper

Greater shares of coal and nuclear may have placed downward pressure on prices from 2019 to 2025, but correlations are weak

- Figure shows the relationship between a state's average coal + nuclear generation share from 2019 to 2025 and the contemporaneous change in retail electricity prices
- Visually suggests that greater coal + nuclear shares may have placed downward pressure on retail prices
- Exploratory statistical analysis also suggests that higher shares of coal+nuclear *may* be associated with declining inflation-adjusted retail prices over this period, but the results are not statistically significant
- Additional analysis would be necessary to accurately assess historical relationships between generation sources and retail prices

Average Coal+Nuclear Share vs. Retail Price Changes: 2019 to 2025

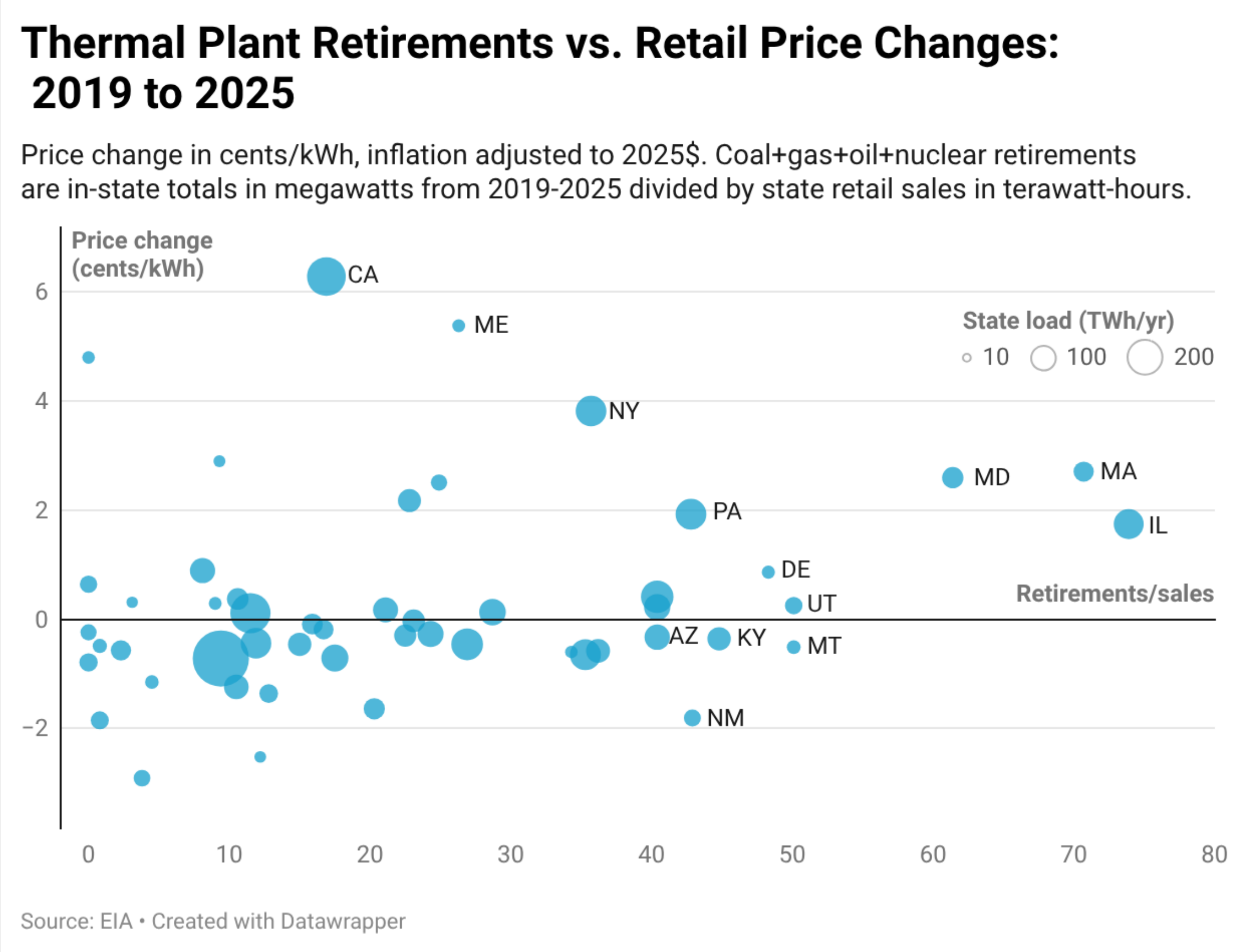
Price change in cents/kWh, inflation adjusted to 2025$. Coal+nuclear market share is in-state average share of generation from coal+nuclear from 2019 to 2025.



Source: EIA • Created with Datawrapper

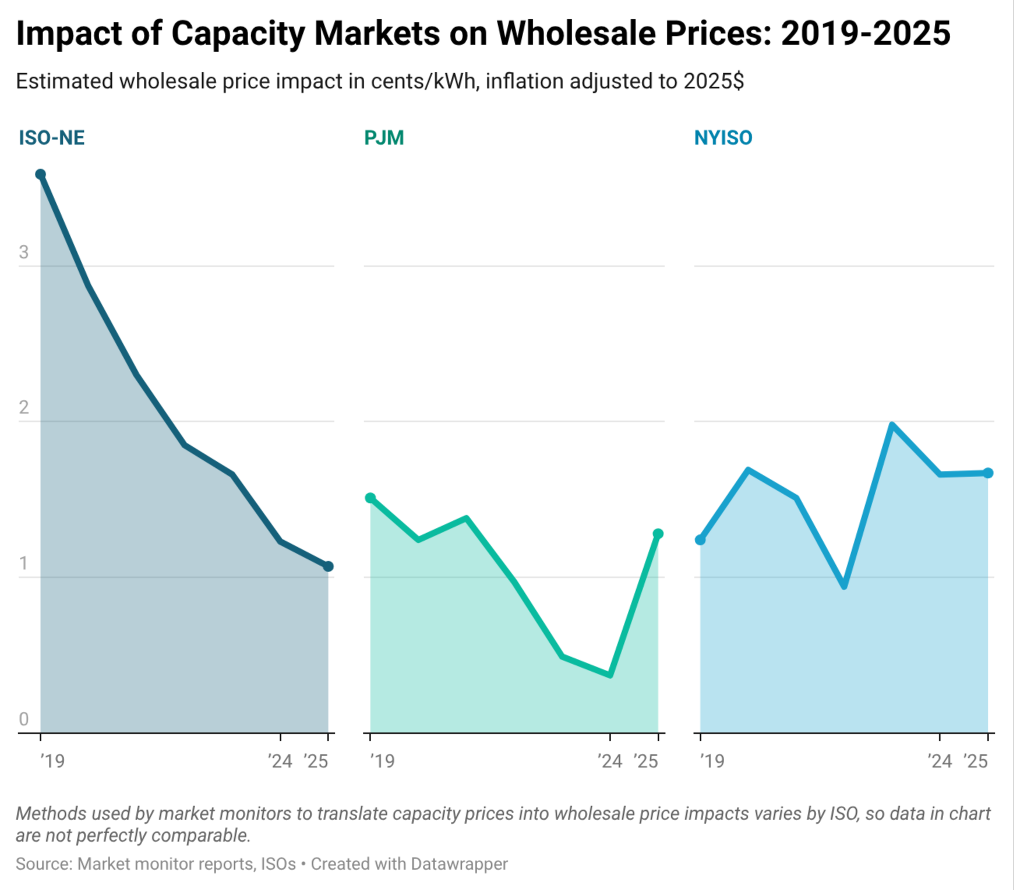
The relationship between state-level thermal-plant retirements from 2019 to 2025 and change in retail prices is unclear, and may change in the future

- Figure shows the relationship between a state's total thermal (coal+gas+oil+nuclear) retirements from 2019 to 2025 (in MW, normalized by retail sales in TWh) and the contemporaneous change in retail electricity prices
- It is hard to discern a clear relationship from the simple figure; detailed statistical analysis or case studies would be necessary to accurately assess the historical relationships
- However, historical relationships may not be relevant going forward, given accelerating actual and prospective load growth



Capacity markets had varied impacts on wholesale (and therefore retail) electricity prices over the 2019 to 2025 period

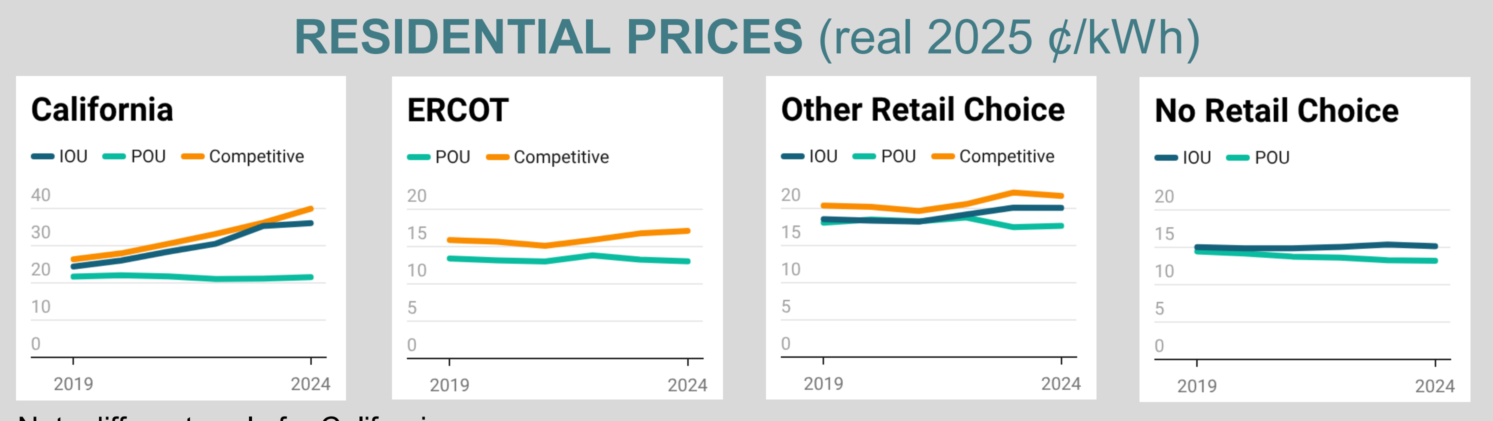
- 3 ISOs have organized capacity markets that cover sizable fractions of capacity needs; figure shows the impact of capacity markets and costs on region-wide average wholesale prices
- Capacity market in **PJM** increased avg. wholesale prices by **0.9 ¢/kWh** from 2024 to 2025, with a further **+0.6 ¢/kWh** impact expected in 2026 (see earlier slide)
- Impacts in PJM are not entirely unique as shown by NYISO & ISO-NE, but note that “regional averages” obscure larger (or smaller) impacts as some states / suppliers have capacity hedges or self-provide
- Capacity price impacts in ISO-NE declined sharply since 2019, placing downward pressure on retail prices; in NYISO, impacts were variable but grew
- Not depicted, but relevant to retail electricity prices *(though translation of below prices to retail is not 1-for-1):*
  - MISO: capacity price auction cleared at $6.5/kW-mo for 2025-26, compared to $0.1/kW-mo for 2019-20
  - CAISO: bilateral capacity prices rose to >$10/kW-mo since 2023 (higher than PJM), vs. $3.5/kW-mo in 2019



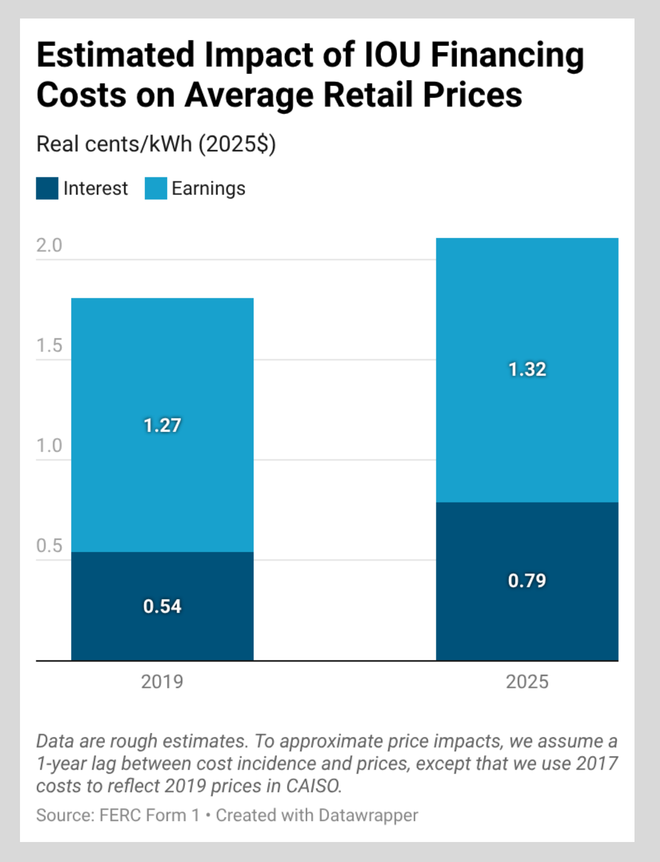
Note: Capacity market results were impacted by the balance between supply and demand along with many regional revisions to market design

The impact of growth in IOU capital expenditure on financing costs may be a *partial* contributor to price differences vs. publicly owned utilities

- Based on FERC Form 1, growth in total IOU CapEx resulted in an increase in the aggregate rate base, from **$1.11 trillion in 2019** to **$1.25 trillion in 2024** in real 2025$; rate base growth increases prices via depreciation and through debt interest payments & shareholder earnings
- Nationally, impact of **interest & earnings** on prices was **~0.3 ¢/kWh** from 2019-2025 (real$)
  - Larger increases: CA (~1.1 ¢/kWh), Southeast (~0.8 ¢/kWh), NY (~0.6 ¢/kWh)
- This may explain **a portion** of the **growing gap** between IOU and publicly-owned utility (POU) prices—but only a minority
  - Growth in IOU vs. POU price differences vary regionally but are generally increasing; other factors must be at play, e.g. (1) different exposure to wildfire risk & storms, (2) POU access to low-cost debt & federal hydro, (3) different taxes, (4) state policies targeting IOUs; (5) differences in service territories



Note different scale for California

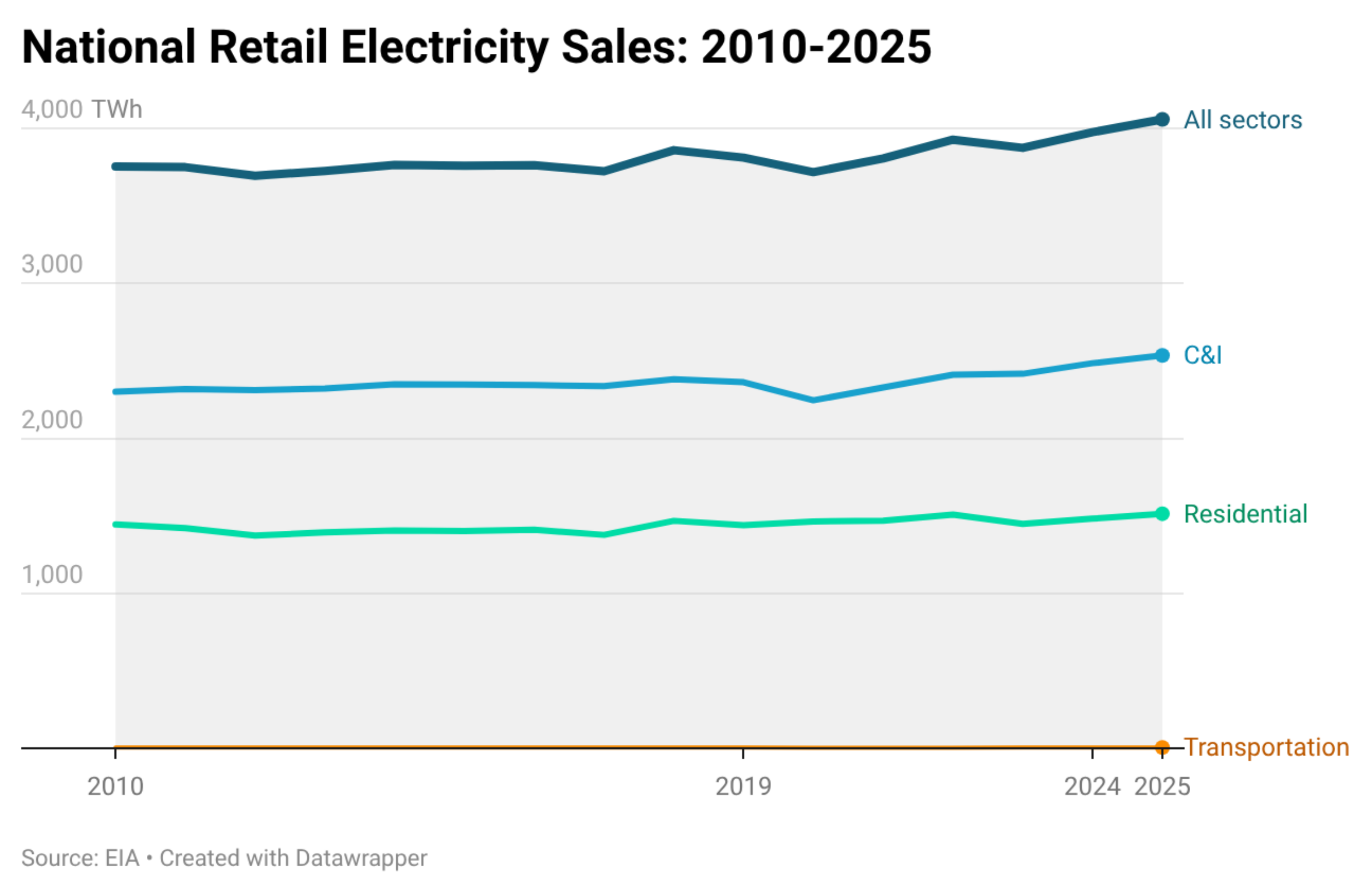


LAWRENCE BERKELEY NATIONAL LABORATORY

Deep Dive – *Accelerated load growth*

After a long period of slow growth, national electricity demand has begun a more-rapid rise—driven largely by commercial and industrial customers

- Figure shows retail sales[1] to end-use customers
- Compound annual growth rate (CAGR) has increased:
  - 2010-2019: 0.2%/yr
  - 2019-2025 = 1.1%/yr
- Year-over-year growth from 2024-2025 = 2.1% *(following 2.6% from 2023-2024)*
- C&I = larger share of recent growth, e.g., 2019-2025:
  - TWh growth: 70% C&I, 30% residential
  - CAGRs: 1.2% C&I, 0.8% residential

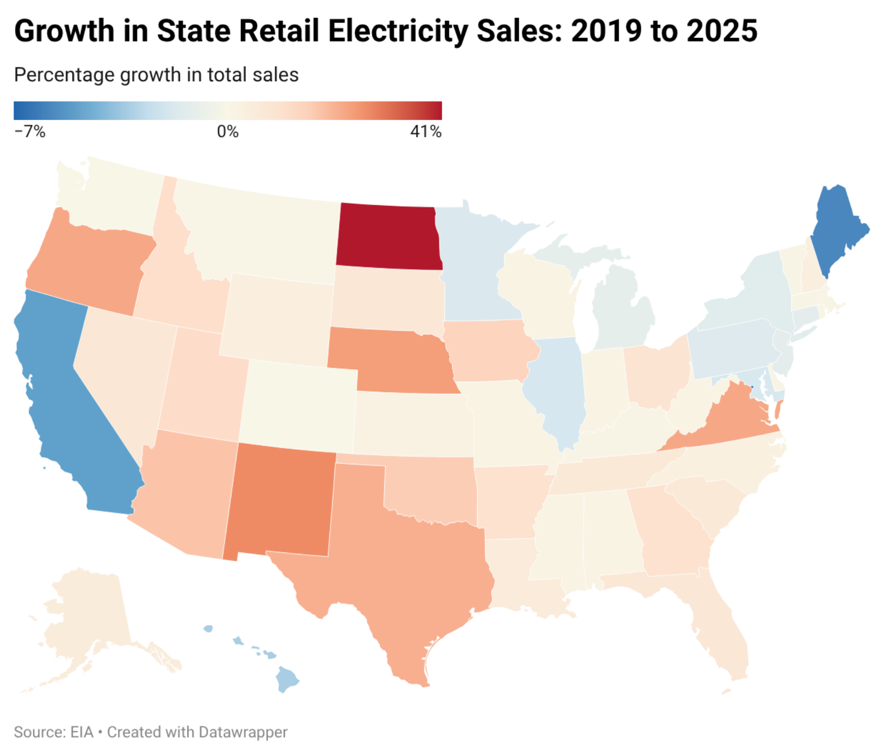


[1] Retail sales represent electricity sales to end use customers via the grid and so exclude any electricity demand that is met through customer-sited resources

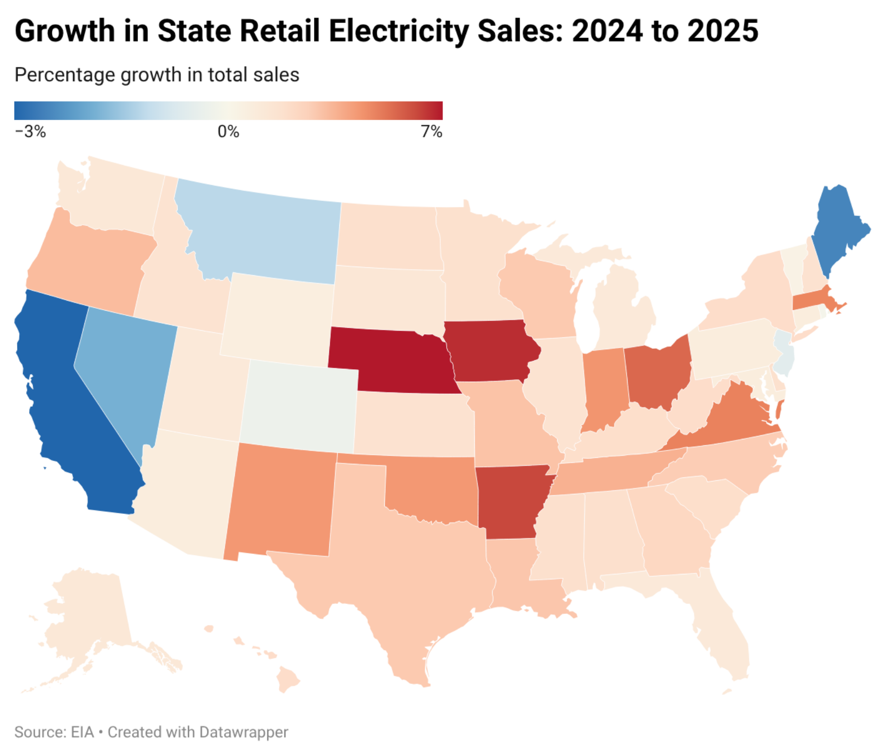
Recent growth is uneven across states, with some seeing a decline in retail sales, others an increase: since 2019 (*left*) and 2024 (*right*)

- 2019-2025: highest in North Dakota, New Mexico, Nebraska, Virginia, Oregon, Texas
- 2024-2025: highest in Nebraska, Iowa, Arkansas, Ohio, Virginia, Massachusetts
- Declining retail sales in some states is due in part to behind-the-meter solar

LONGER PERIOD: 2019-2025

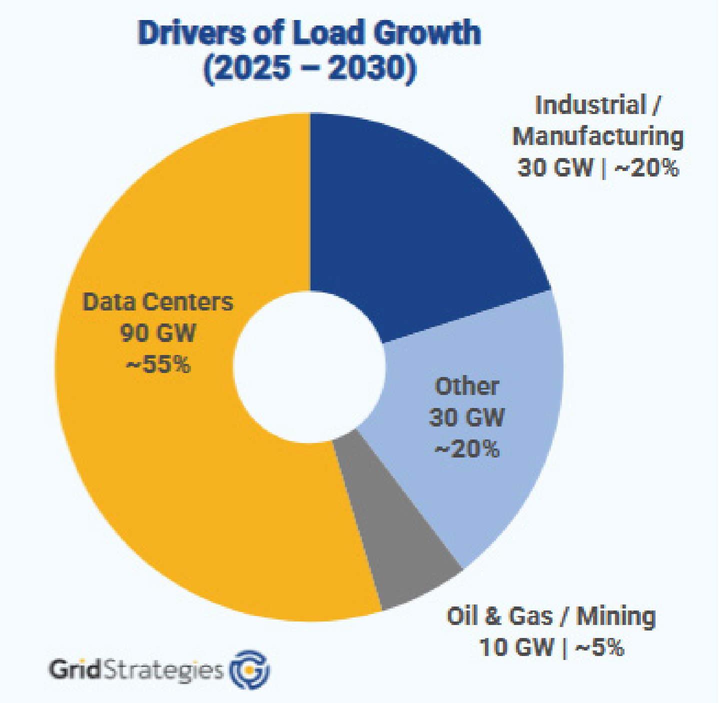


YEAR-OVER-YEAR: 2024-2025



Significant additional load growth is anticipated, but with substantial uncertainty on amount *(which may, in part, depend on price trajectories)*

- Example: Grid Strategies[1] compiled data on load growth projections through 2030, submitted by utilities to FERC:
  - 5.7%/year forecasted growth in electricity use, 2025-2030
  - 3.7%/year forecasted growth in peak demand, 2025-2030
  - Higher growth in use vs. peak implies a growing load factor compared to current and past values
- FERC submissions show data centers as largest driver:
  - Grid Strategies notes that the 90 GW from data centers may be overstated by 25 GW, but remains dominant
  - More generally, Grid Strategies highlights both significant recent increases in growth expectations and the significant uncertainty

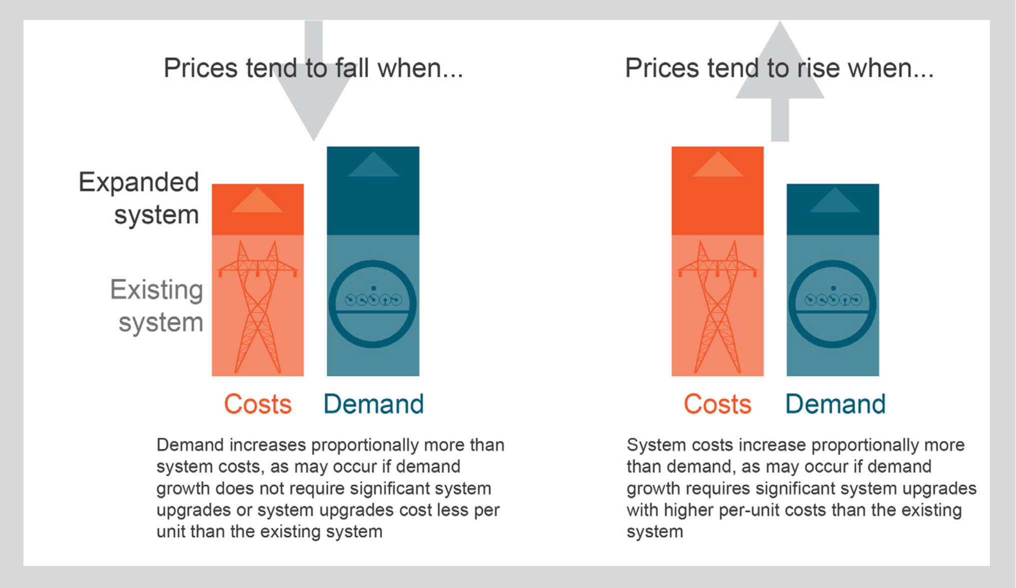


- NERC reports a potential 224 GW growth in summer peak demand over the next 10 years[2]
- Focusing solely on data centers, in late 2024, LBNL estimated:[3]
  - Data centers consumed about 4.4% of total U.S. electricity in 2023
  - Uncertain growth: could consume between 6.7% and 12% of total U.S. electricity by 2028

[1] Grid Strategies (2025); [2] NERC (2025); [3] Shehabi et al. (2024)

Load growth can increase or decrease retail prices: depends on ability to optimize existing assets, cost of new supply & delivery, tariff structures

- Electricity service entails a large share of **fixed costs "sunk" in grid infrastructure**. All else equal, average (per-unit) costs and thus retail prices tend to go down when these costs are spread over more sales.
- Demand growth may, therefore, at least in the long term, lower prices. However, the growth projected over the next decade is substantial, and there are conditions under which growth will increase prices.
  - Case studies in later slides illustrate both possibilities
- Three additional factors affect how load impacts prices:



1. System utilization
All grids can absorb demand growth, to a degree, by utilizing "spare" capacity in existing assets. The degree to which new demand can optimize the use of existing assets—such as through load flexibility or simply via a high load factor—is a key determinant of the impacts of demand growth on prices.

2. System costs
Demand growth will impose new variable costs and investments in grid infrastructure. The impact on overall average costs and therefore prices depends on the relative size of these new "marginal" costs versus the average cost of the existing electricity system.

3. Cost allocation & recovery
Retail electricity prices emerge from the allocation of system costs to specific customers. Cost allocation practices will determine how cost increases or savings are allocated to different customers and will therefore determine the net impacts of demand growth on customer-specific prices.

- **Market structure** (vertical integration vs. restructured) can also influence relationships, as it can impact how marginal costs impact retail prices in the near term and how costs are allocated among customers

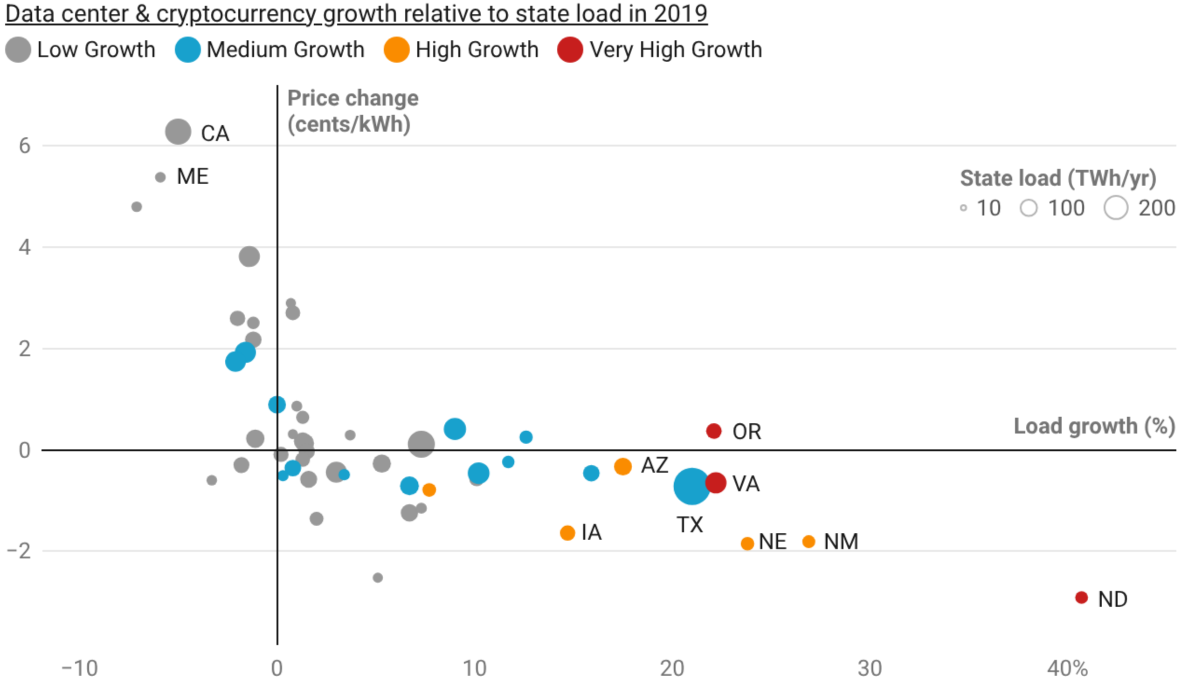
State-level load growth was associated with declining all-sector average retail prices in recent decades, including from 2019 to 2025 in most states

- From 2019 to 2025, states with the highest growth generally saw average retail prices decline in real terms
  - **Over 1 ¢/kWh reduction in all-sector average prices in highest-growth states**, based on earlier statistical analysis
- Those states where load declined often experienced price increases
- Cost growth significantly driven by T&D investments—with prevailing rate structures, greater load can lead to fixed costs being spread over more demand, reducing per unit costs *(though impact is bi-directional, as price reductions should also increase load)*
- Note: Commercial sector saw most load growth; had largest price reductions

ALL-SECTOR AVG. PRICES VS. TOTAL GROWTH

Load Growth vs. Retail Price Changes: 2019 to 2025

Price change in cents/kWh, inflation adjusted to 2025$. Load growth is percent change in retail sales.



Data center and cryptocurrency growth defined as increase in MWs from 2019-2024, relative to 2019 state load. Very high = > 45 MW/MWh; High = > 15 MW/MWh; Medium = > 5 MW/MWh

Source: EIA, S&P Global • Created with Datawrapper

Note: Presence of significant data center load does not appear to alter conclusions

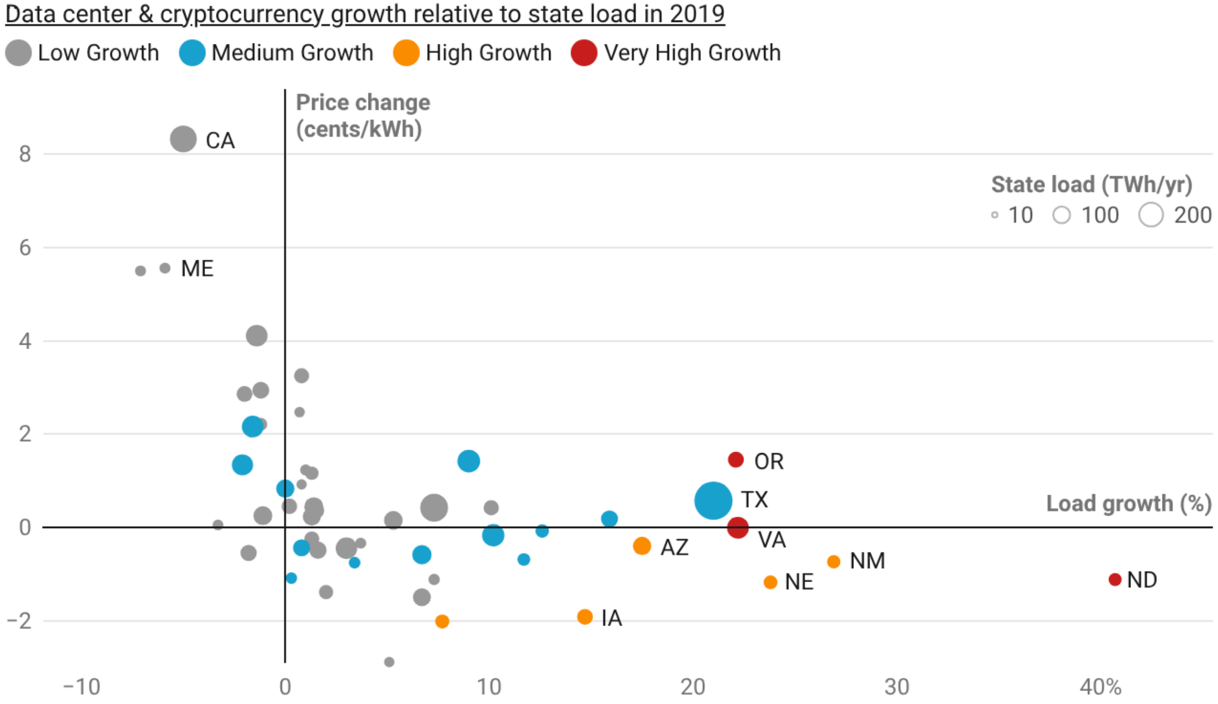
Residential customers may have benefited from load growth from 2019 to 2025 in some states, but the relationship is less clear and may change

- Figure depicts relationship between total state-level load growth and average residential prices from 2019 to 2025
- The relationship between residential prices and load growth is not as clear as for all-sector average prices
  - To some degree, as expected: if growth was mostly C&I, then *typical* cost allocation practices should not shift costs or benefits to households
  - Residential customers in some states appear to have benefitted, or at least not been injured, from state-level load growth
- States with contracting load were often those with higher price increases
- The presence of significant data center and cryptocurrency growth does not appear to alter these conclusions
- Past need not be prelude, illustrated by the PJM example on a later slide

RESIDENTIAL PRICES VS. TOTAL GROWTH

Load Growth vs. Residential Price Change: 2019 to 2025

Price change in cents/kWh, inflation adjusted to 2025$. Load growth is percent change in retail sales.



Data center and cryptocurrency growth defined as increase in MWs from 2019-2024, relative to 2019 state load. Very high = > 45 MW/MWh; High = > 15 MW/MWh; Medium = > 5 MW/MWh.

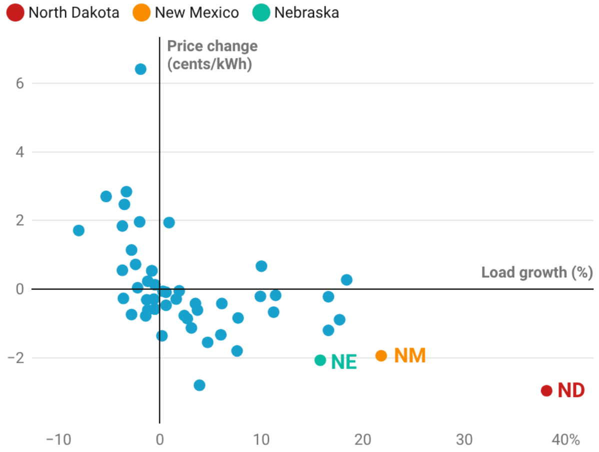
Source: EIA, S&P Global • Created with Datawrapper

Case Study: North Dakota, New Mexico & Nebraska increased load and lowered prices

Managing load growth while reducing inflation-adjusted retail prices (with data through 2024[1])

1 Three states have significantly increased load while reducing inflation-adjusted retail prices

Load Growth vs. Price Change: 2019 to 2024

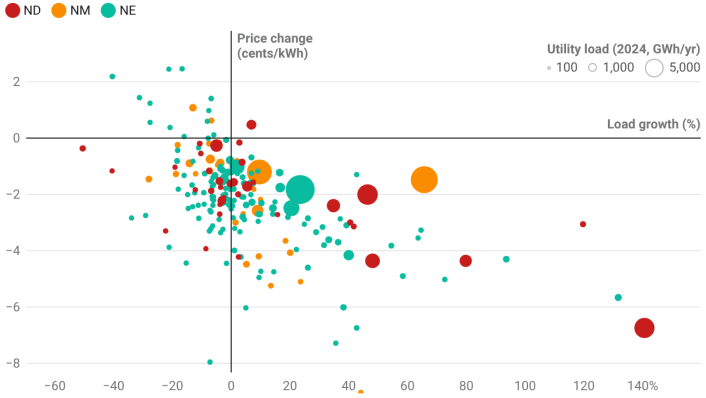


Source: EIA • Created with Datawrapper

2 Utilities with the greatest load growth generally experienced the largest reduction in prices

Impact of Load Growth on Utility-Level Average Retail Price Changes in North Dakota, New Mexico, Nebraska: 2019 to 2024

Price change in cents/kWh, inflation adjusted to 2025$. Load growth in percentage terms from 2019 to 2024. A few small-utility outliers are excluded due to the y-axis scale.



Source: EIA • Created with Datawrapper

3 Utilities with sizable C&I growth lowered C&I prices; residential customers were not harmed

ND, NM, NE: Impact of Utility- & Sector- Specific Load Growth on Retail Price Changes from 2019 to 2024

Price change in cents/kWh, inflation adjusted to 2025$.

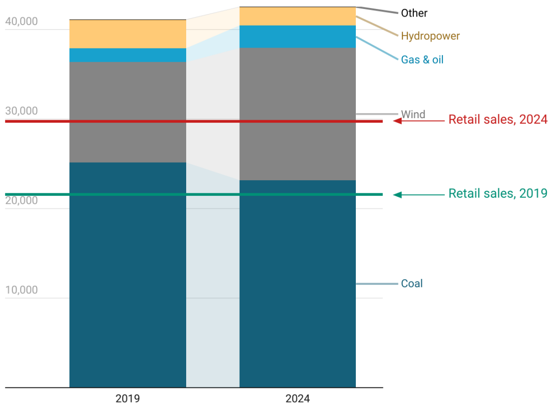
Utility Grouping	Residential Load Growth	Residential Price Change	C&I Load Growth	C&I Price Change
High Load Growth: >20%	−1%	−1.3	64%	−2.7
Low Load Growth: 0-20%	4%	−1.3	10%	−1.4
Negative Growth: <0%	−2%	−0.9	−10%	−0.9

Source: EIA • Created with Datawrapper

4 Load growth matched with abundant, low-cost energy enabled positive outcomes

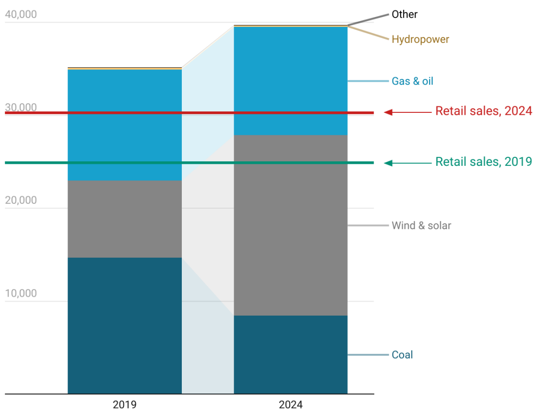
- Substantial C&I growth enabled fixed costs to be spread over more load
- Abundant, low-cost energy enabled load to be served at low incremental cost

North Dakota Generation and Retail Sales (GWh)



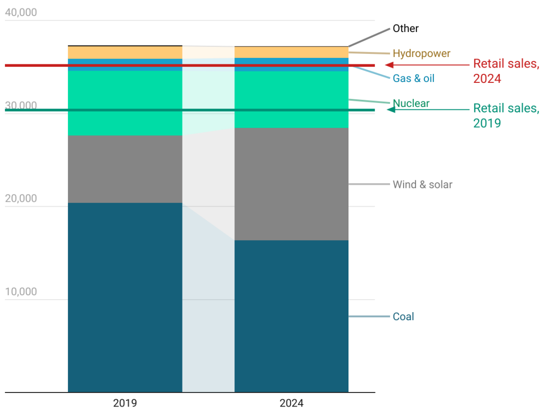
Source: EIA • Created with Datawrapper

New Mexico Generation and Retail Sales (GWh)



Source: EIA • Created with Datawrapper

Nebraska Generation and Retail Sales (GWh)



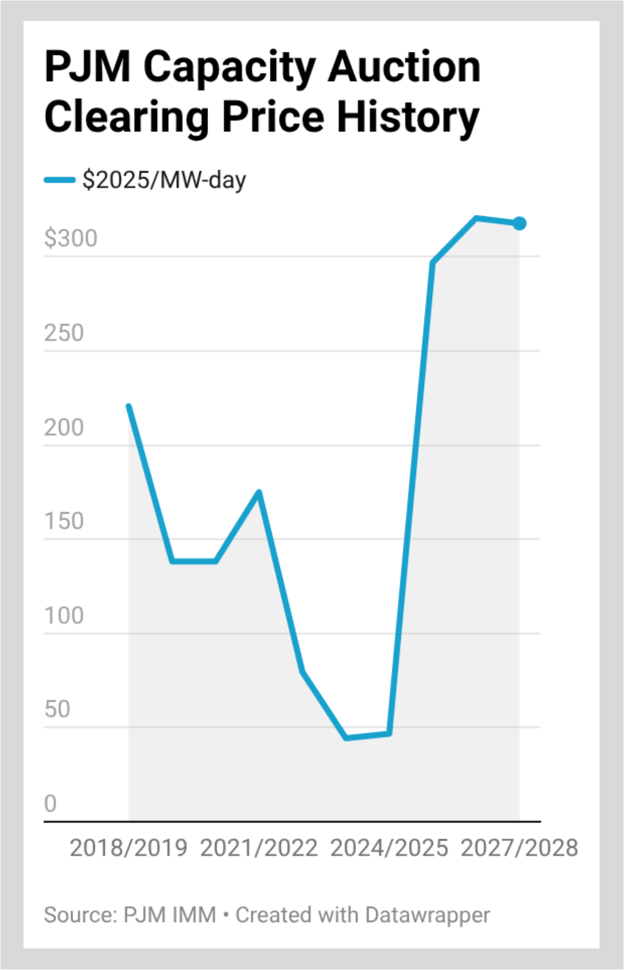
Source: EIA • Created with Datawrapper

[1] Utility-level EIA data only available through 2024, so slide focuses on 2019-2024

Case Study: PJM Capacity Auction demonstrates price increases with load growth

Accelerated load growth combined with supply and delivery constraints leads to significant price increases

1 Significant increase in PJM capacity prices



Nominal price data from PJM IMM; note that capacity auction results are impacted by the supply-demand balance as well as multiple revisions to capacity-market design

2 PJM's capacity prices increased due to multiple factors, including load growth

Data Center Load Growth

174% increase in auction revenues

Summer Capacity Ratings for CC/CTs

23 - 118% increase in auction revenues

Demand Curve Price Cap

68% increase in auction revenues

Adoption of ELCC Method

49% increase in auction revenues

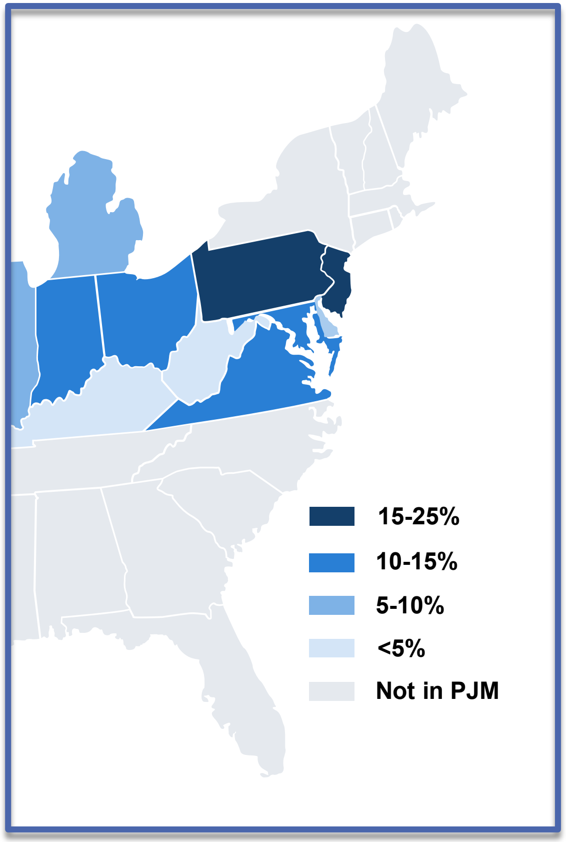
Capacity prices are one but not the only contributor to retail price increases

Other major drivers included the exclusion of Reliability Must Run units from the auction supply curve and the withholding of exempt capacity. The resulting auction outcomes signal a need for new resources to meet the growing demand of the region. Some may therefore interpret the increase in clearing prices as indicative of prices that were, in retrospect, too low in previous auctions.

Source: Data from Monitoring Analytics' IMM Analysis of the 2025/2026 RPM Base Residual Auction Parts A through G

3 Significant increase in state-level retail prices

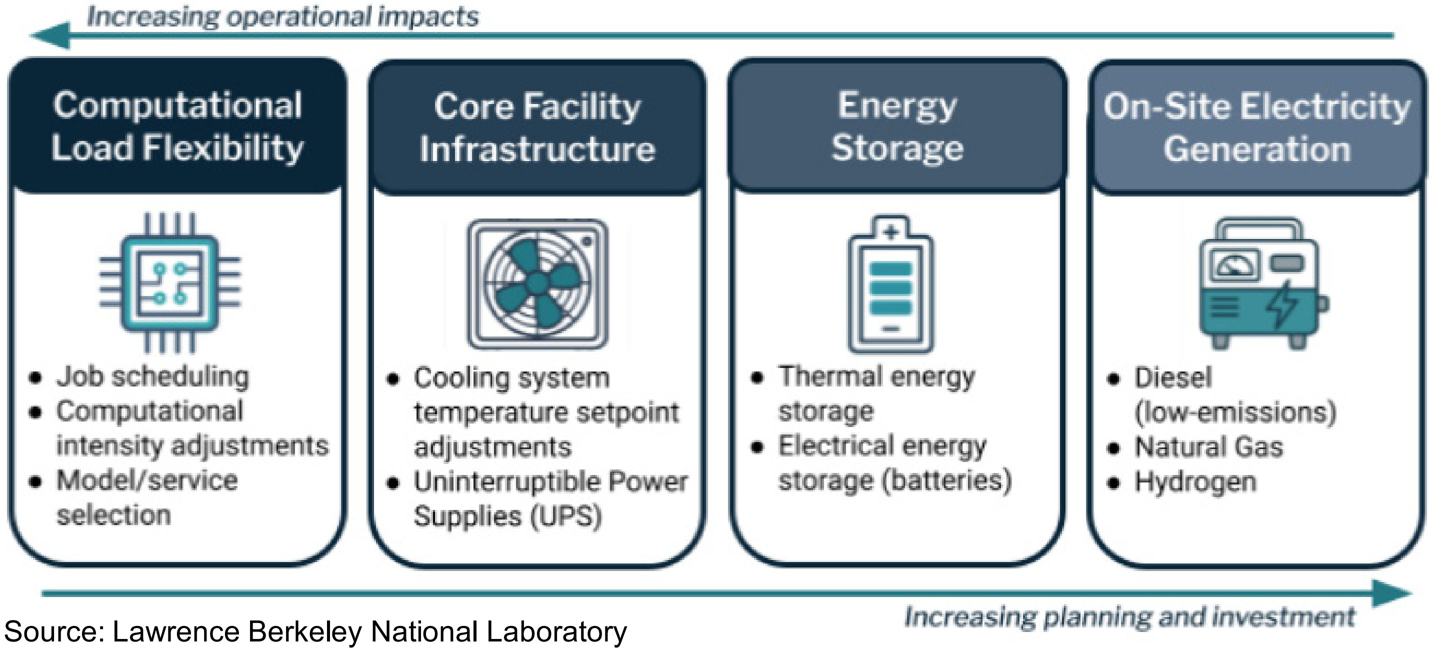
Average Increase in Nominal Prices: Dec. 2024 to Dec. 2025



Notes and source: States with vertically integrated utilities are shielded to some extent from capacity auction price spikes because utilities can self-supply instead of purchasing capacity from PJM: from EIA Electricity Monthly Update Dec. 2025

Maximizing the use of the existing grid and encouraging bring-your-own-generation (BYOG) can facilitate large-load additions in the near-term

- New loads eventually require new supply and delivery infrastructure, but that is constrained and will take time; in the meantime, there are opportunities to minimize broader system impacts
- Three broad options for increasing asset utilization and reducing system-level impacts include:
  - Demand flexibility or onsite generation or storage from the new loads *(depicted in figure)*
  - Enabling data centers to "bring-their-own" offsite generation, storage, or load flexibility
  - Broader utilization of load flexibility, efficiency, storage, grid-enhancing technology, regional trade, etc.

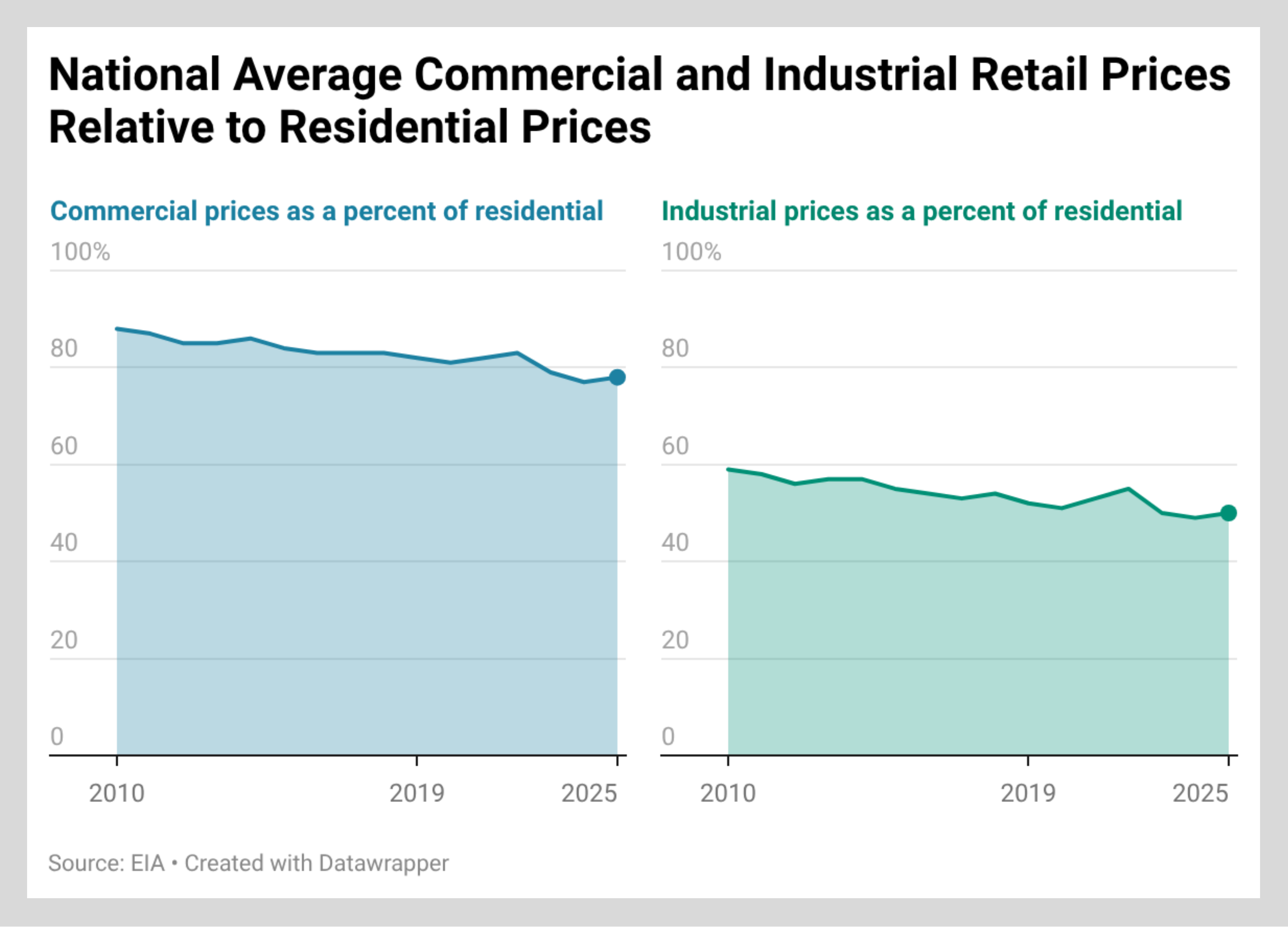


Source: Lawrence Berkeley National Laboratory

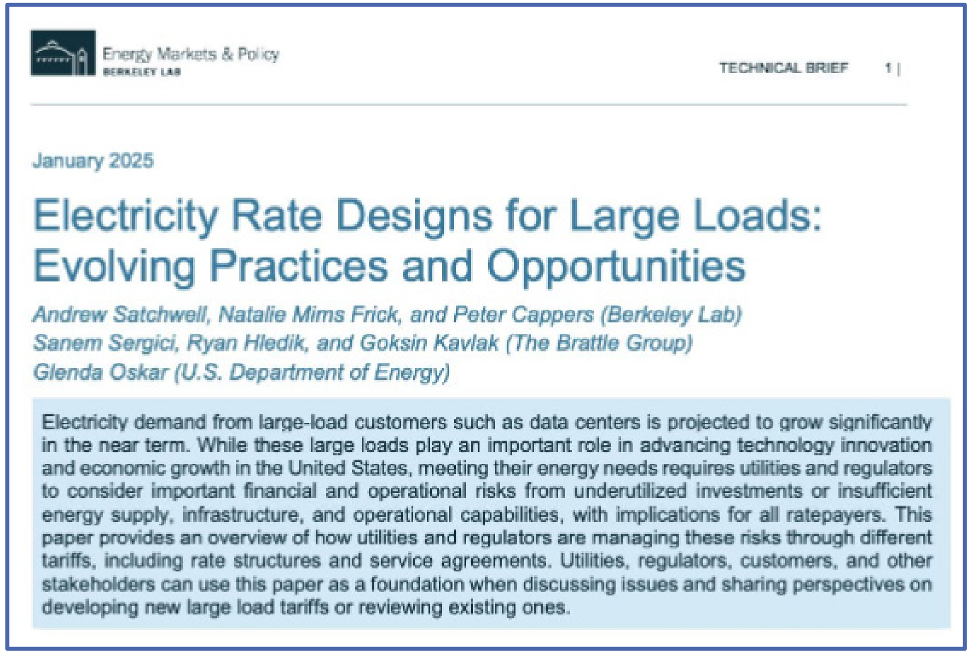
Some relevant recent studies on these options and their potential benefits include: EPRI (2026), Brattle (2026), ASE (2026), Ross & Ewing (2026), Camus (2025),

Historically, the gap between residential and C&I prices has grown over time, with households bearing a larger share of total electric-sector costs

- Average C&I prices have increasingly diverged from residential prices, though with a slight reversion in 2025
- May be due, in part, to distribution cost growth, as those costs are primarily allocated to smaller customers
- If load growth occurs in a supply/delivery-constrained environment, protecting residential customers may require allocating more total costs to the new loads
- New large-load tariffs are one approach to protect residential customers *(see next slide)*



Rapid data center buildout plus supply and delivery constraints can increase costs ➡ Interest in new large-load tariffs to mitigate impacts



Energy Markets & Policy BERKELEY LAB

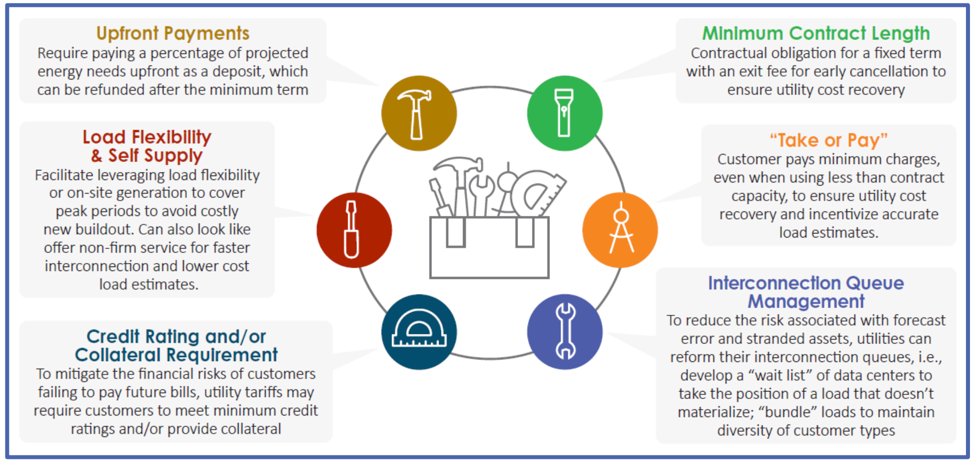
TECHNICAL BRIEF 1 |

January 2025

Electricity Rate Designs for Large Loads: Evolving Practices and Opportunities

Andrew Satchwell, Natalie Mims Frick, and Peter Cappers (Berkeley Lab)
Sanem Sergici, Ryan Hledik, and Goksin Kavlak (The Brattle Group)
Glenda Oskar (U.S. Department of Energy)

Electricity demand from large-load customers such as data centers is projected to grow significantly in the near term. While these large loads play an important role in advancing technology innovation and economic growth in the United States, meeting their energy needs requires utilities and regulators to consider important financial and operational risks from underutilized investments or insufficient energy supply, infrastructure, and operational capabilities, with implications for all ratepayers. This paper provides an overview of how utilities and regulators are managing these risks through different tariffs, including rate structures and service agreements. Utilities, regulators, customers, and other stakeholders can use this paper as a foundation when discussing issues and sharing perspectives on developing new large load tariffs or reviewing existing ones.



Source: E3 report

- Large-load tariff info: LBNL report, E3 report, data
- Four themes of large load tariffs
  - Fairly allocate electricity system costs to cost causers
  - Mitigate utility and customer financial risks
  - Mitigate operational and resource adequacy risks
  - Accommodate needs of large-load customers
- Examples of types of provisions
  - Refined cost allocation approaches to ensure fair payments
    - Sometimes including payments for embedded costs
  - Min. duration & demand/payment, exit fees, reassignment
  - Upfront commitments, collateral, credit
  - Size, ramp times, load factor, BTM resources
- Other levers to mitigate impacts:
  - Interconnection, cost allocation among existing rate classes, load forecasting, information sharing, third-party gen, etc.
- *Note: to a degree, these new tariffs and processes may diverge from historical practice of industrial development rates that sought to encourage loads through accommodating tariffs*

Example statements that *suggest* possible benefits for other customers, but positive outcomes are not assured and require monitoring

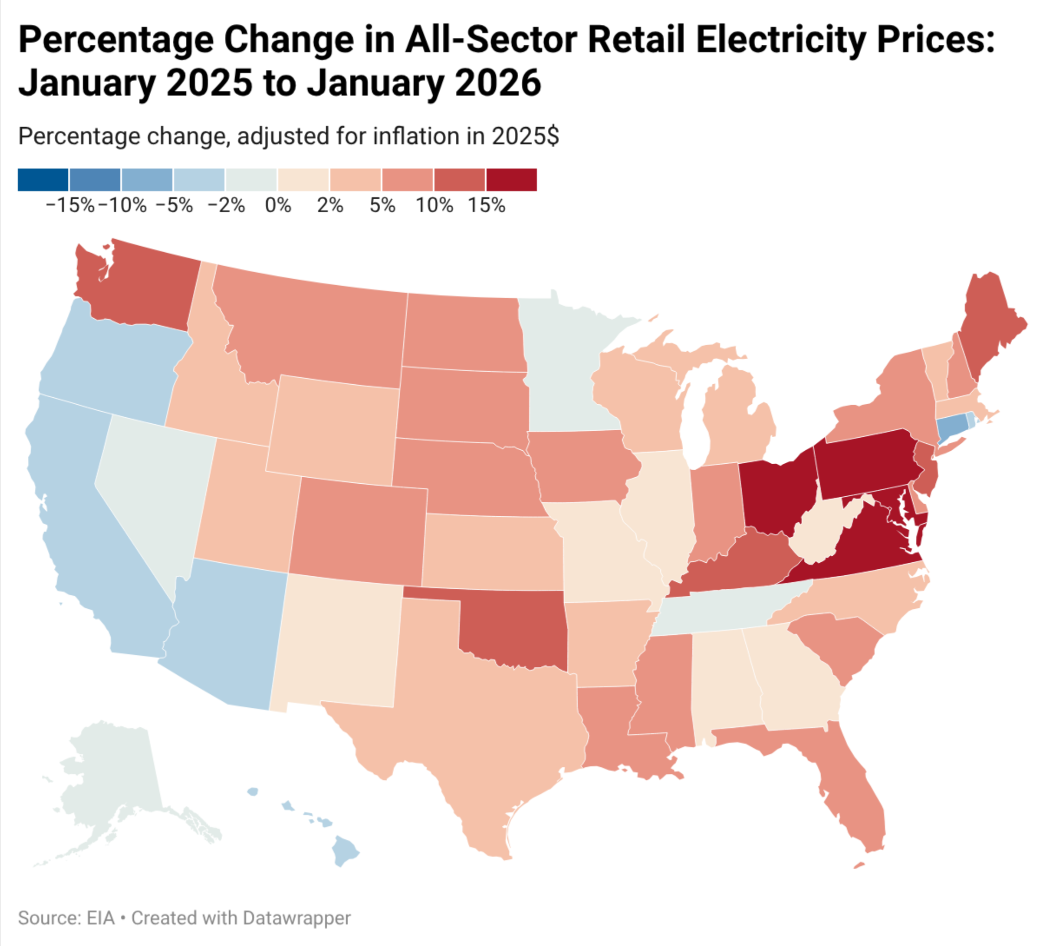
Georgia Power	Georgia PSC approved utility to serve new large loads, conditioned on growth placing **downward pressure on bills of $8.50/mo** for residential customers from 2029-2031
DTE Energy	Michigan PUC conditionally approved data center contracts that DTE estimates will **lower residential costs by 8%;** separate agreement with Google claimed to have **$1.7 billion in lifetime benefits**
MONTANA-DAKOTA UTILITIES CO. A Division of MDU Resources Group, Inc.	MDU estimates Applied Digital's data centers **saved customers $70 in previous year** by tapping into underutilized power and, with full build, savings could rise to $250/year
NIPSCO A NiSource Company	NIPSCO estimates $1 billion in bill credits over a 15-yr contract with Amazon data centers in Indiana, equal to **residential bill savings of $7-9 per month** in 2032 and beyond
PG&E Pacific Gas and Electric Company	PG&E estimates that 10 GW of data center growth could **lower customer bills by 10%** by utilizing existing infrastructure and spreading fixed costs across more electricity usage
entergy	Entergy projects **$5 billion in savings over 20 years** for their customers in Arkansas, Louisiana and Mississippi due to the data center agreements in those states

Emphasizing the point that these are possible or stated benefits, there is risk that the new tariff structures will be insufficient to fully protect other customers (e.g., see Martin & Peskoe 2025)

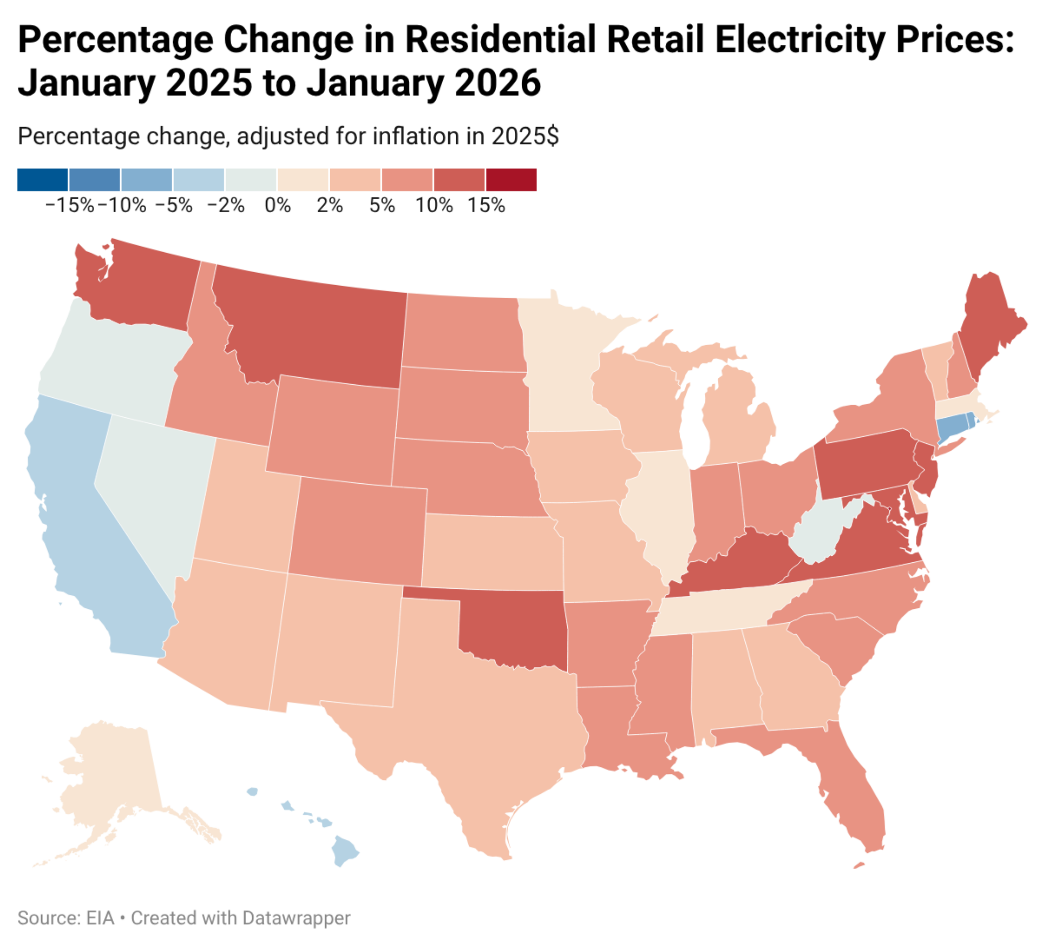
Early 2026 price indicators and IOU rate requests – *What's coming down the pike*

Retail prices continue to climb in 2026: all-sector average *(left)* and residential *(right)* price changes, January 2025 to January 2026

ALL-SECTOR AVERAGE

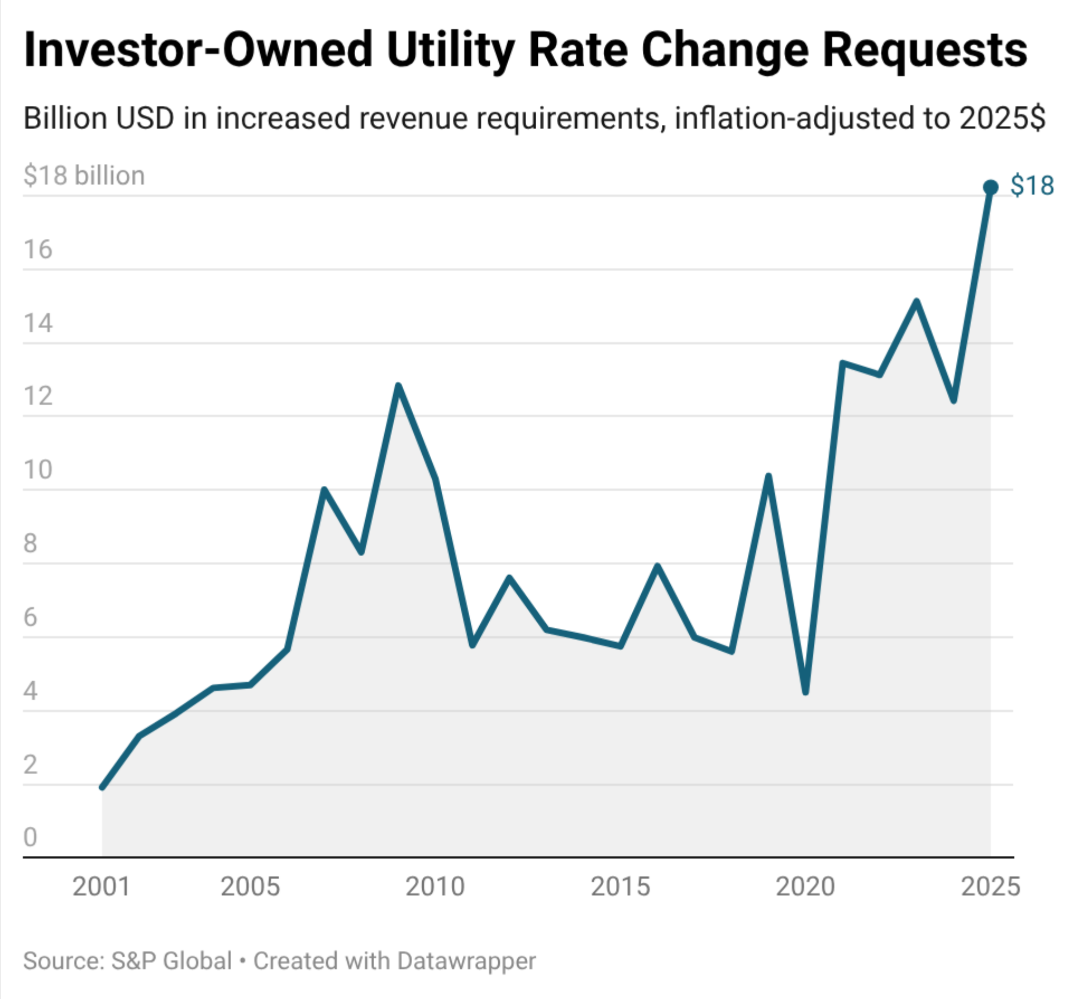


RESIDENTIAL



Investor-owned utility revenue increase requests in 2025 were higher than experienced in decades, suggesting continued price increases in 2026

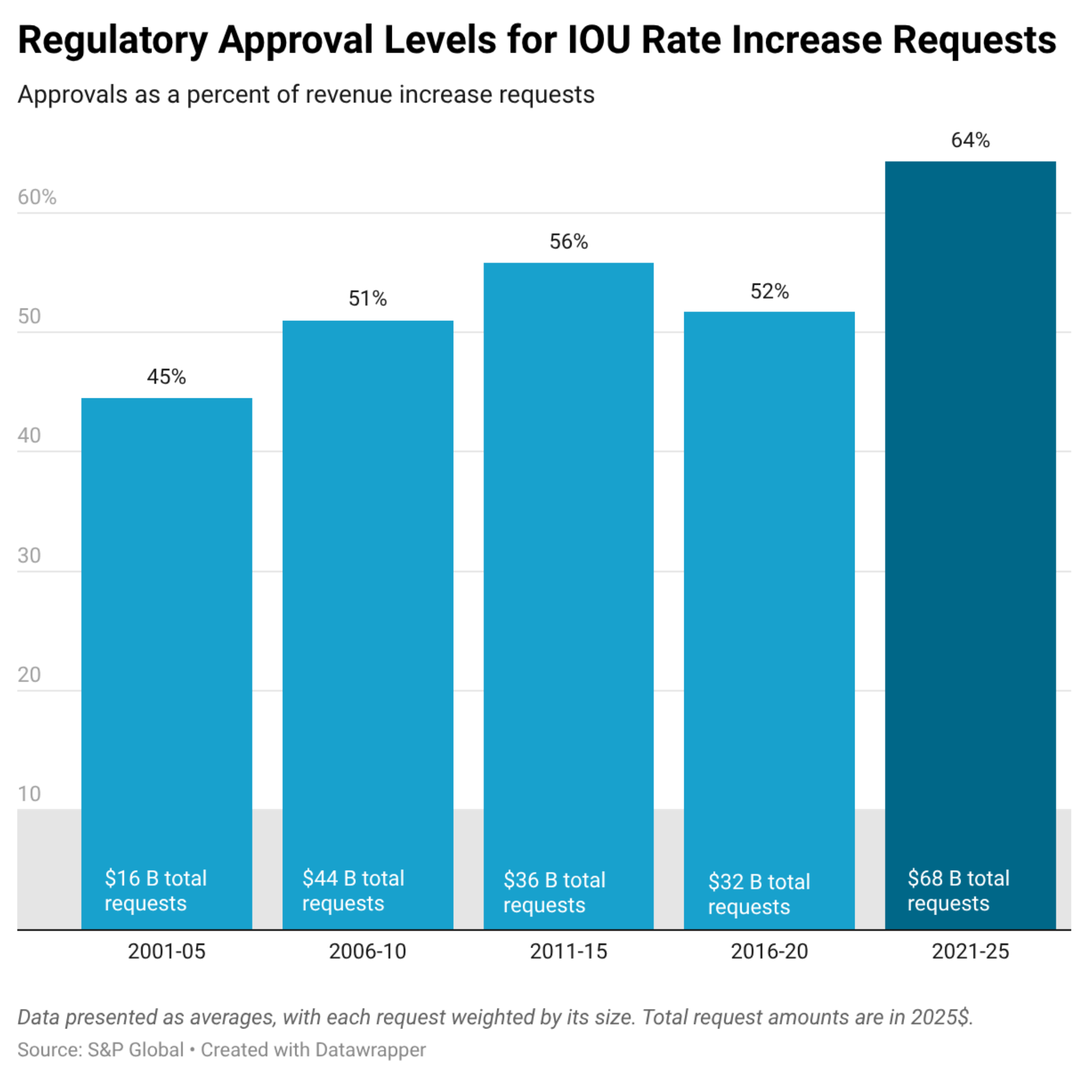
- Investor-owned utility (IOU) revenue increase requests in 2025 = $**18 billion** *(focusing on subset of requests, see below)*
- IOU revenue increase requests in 2025 exceeded any point since the mid-1980s, suggesting continued price increases in near term as regulators consider the requests
- S&P data reflect major 'base rate' requests and some rate riders, but generally exclude fuel adjustment charges, storm recovery costs, and other limited-term riders; the data also only includes IOUs, as other utility types do not generally file with state PUCs
- Data therefore represent a directional signal for changes in costs and near-term retail electricity prices, but are incomplete



Notes: (1) Source: S&P Global, LBNL Analysis; (2) Rate case sample includes all "major" rate cases that impact base rates and would result in a rate change of at least $5 million, inclusive of some limited issue rider cases. Fuel cost adjustments and limited-term rate riders are not generally captured.

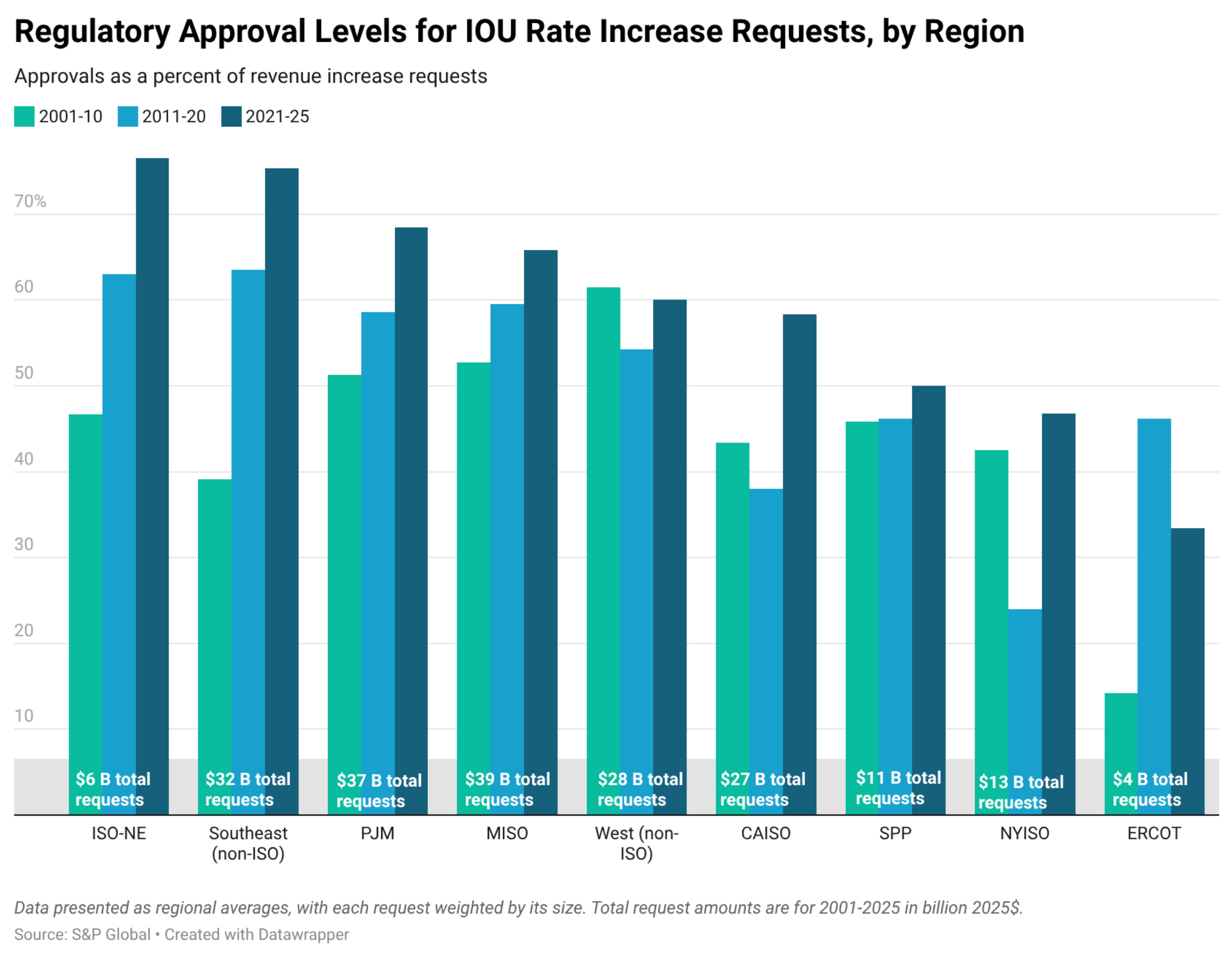
Further suggesting price increases, regulators approved larger fractions of utility revenue increase requests over the last 5 years than previously

- Over the last five years, public utility commissions (PUCs) approved, on average, **64%** of the dollar value of revenue increase requests; in 2025, it was **66%**, on average
- This is higher than in the previous two decades, during which the average approval percentage was **52%**
- Higher approval levels could imply: higher-quality utility requests; lower levels of scrutiny; or changes in operating, regulatory or legislative environment
- Regardless of the cause, high IOU requests plus high levels of approval suggest additional upward price pressure in the near-term barring load growth that exceeds revenue requirement increases



Recent approval percentages in most regions were higher than in the past: New England and the Southeast approved higher fractions of requests

- Regulatory approval levels for IOU revenue increase requests vary by region, as do time trends
- New England and Southeastern PUCs have recently approved higher percentages, and approval levels have, over time, significantly increased
- Approval levels were relatively high and have also increased among PUCs in PJM and MISO
- California witnessed recent increases in approval levels, but overall percentages were lower than in the regions noted above

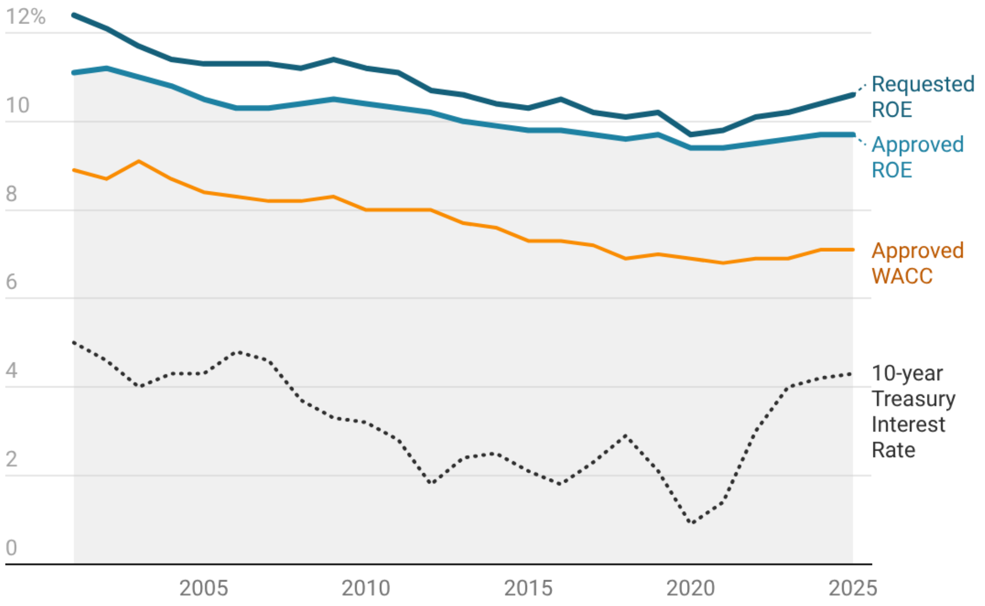


Authorized return-on-equity (ROE) for IOUs also impacts retail rates, and has trended slightly upwards in recent years as interest rates increased

- Regulators in California and the Southeast have recently authorized higher ROEs than in other regions, whereas New England and New York regulators have authorized lower ROEs

Requested and Approved IOU ROE, Approved WACC, and Relationship to 10-year Treasury Interest Rate

Values for ROE and WACC are mean values among all requests or approvals in a year

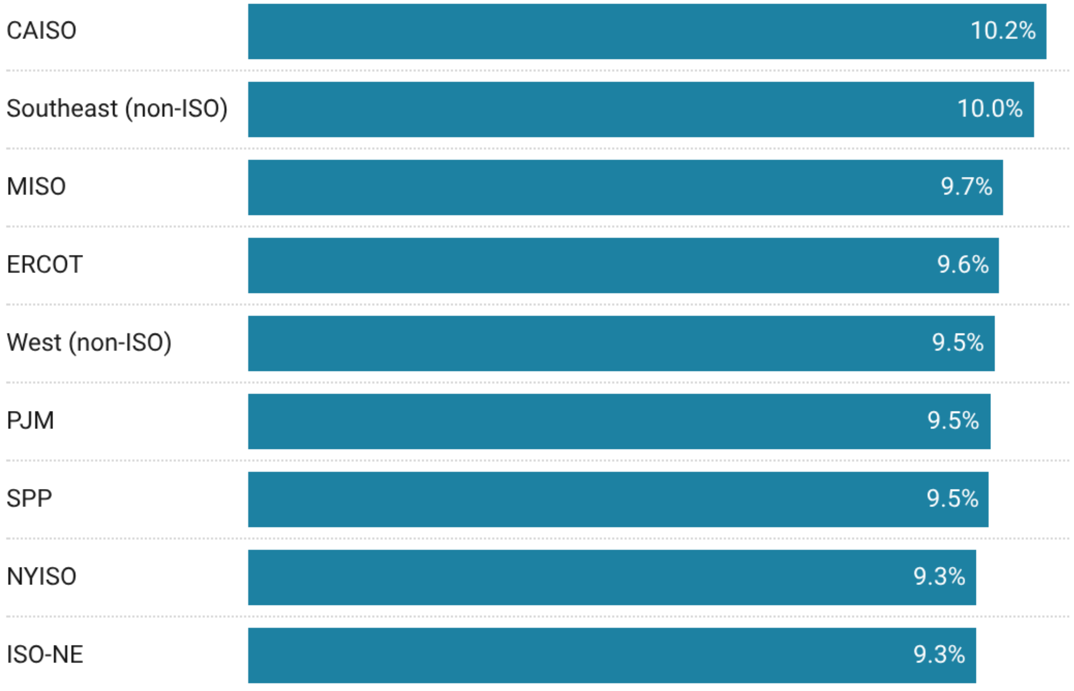


Given time-lags between requests and approvals, the gap between the two values in any individual year does not reflect approval percentages.

Source: S&P Global • Created with Datawrapper

Authorized Return-on-Equity by Region: 2021-2025

Data shown are averages among rate cases in each region



Source: S&P Global • Created with Datawrapper

LAWRENCE BERKELEY NATIONAL LABORATORY

For more information

This Overall Project Currently Includes Multiple Products

For more information, contact: Ryan Wiser (rhwiser@lbl.gov)

Annual and periodic data updates	**Data visualization tools**	**Peer-reviewed journal article**
Compiles and synthesizes data as it becomes available, including this update	Allows users to explore some of the data compiled under this research effort	Highlights a subset of the trends through 2024, with a focus on statistical analysis of broad drivers

These products can all be found at: https://emp.lbl.gov/retail-electricity-price-trends-and-drivers

Acknowledgements:

This work was funded by the U.S. Department of Energy's Office of Critical Minerals and Energy Innovation under Contract No. DE-AC02-05CH11231.