



Factors Influencing Recent Trends in Retail Electricity Prices in the United States

What do we know? Where are the gaps?

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This presentation is a comprehensive summary of our work, and is one aspect of a larger project that has additional data and analysis products

In Addition to this Presentation, the Overall Project Also Includes:

Peer-reviewed journal article

Highlights a subset of the trends, with a focus on statistical analysis of broad drivers

Data visualization tool

Allows users to explore some of the data that underpins the journal article

More-concise presentation

Summarizes the article and provides additional material, more concisely

This presentation is a comprehensive summary of our work to date. If you are looking for something briefer, we recommend the other presentation. Compared to this deck, it lacks:

- Background material on how retail rates and prices are established
- Data on residential electricity bills, bills relative to household income, some sectoral trends
- Trends in utility-level prices, including for investor-owned and publicly-owned utilities
- Some supplementary literature review, figures, and analysis on many of the core drivers of price changes
- Some of the slides that summarize the statistical analysis that is more-fully addressed in the journal article
- Identification of knowledge gaps and broad areas where additional research may be warranted

These products can all be found at: <https://eta-publications.lbl.gov/publications/factors-influencing-recent-trends>

Objectives and scope: understand recent (not future) retail price trends

- Low-cost electricity has long afforded the United States with a competitive economic advantage over many other advanced economies. In recent years, however, retail electricity prices have risen rapidly alongside economy-wide inflation, with much larger increases in some states.
- This study **summarizes what is known about the drivers of recent national and state-level changes in retail electricity prices**. It draws on publicly available data, published literature, and statistical analysis.
- The findings underscore the **diverse set of retail electricity price determinants** in each state and highlight the need for continued research to inform effective policy and ensure long-term customer affordability.
- To that end, we also **identify areas of uncertainty and research gaps** throughout and offer a broad assessment of knowledge gaps at the end of this presentation.
- Note: Retail electricity prices are important, but so too are energy bills and the broader concept of total societal costs and benefits; this study narrowly focuses on retail prices

Additional Details

- This should be considered a scoping-level assessment, and therefore not definitive
- The focus is on overall national and state-level retail electricity prices (averaged across residential, commercial, and industrial sectors), especially recent trends in those prices
- Sector-specific (e.g., residential) and utility-level price trends are highlighted in some places, but are not emphasized
- We often present retail electricity prices in both inflation-adjusted (real 2024\$) and nominal (not inflation-adjusted) terms
- We make no effort to predict how trends may change in the future or assess possible future drivers—which could differ from the past

Differences in average retail prices and recent changes to those prices could be impacted by multiple 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 Study Focuses on a Subset

This study primarily focuses on a subset of factors that may have influenced state-level price changes over the last ~5 years; it does not assess all possible drivers, but instead emphasizes the most-likely candidates to have recently and significantly impacted prices:

- Age-based replacement and supply-chain constraints for T&D
- Natural disasters, extreme weather, and wildfire mitigation
- Natural-gas price fluctuations and exposure
- Electricity load growth or contractions
- Utility-scale wind and solar deployment
- State renewables portfolio standard (RPS) programs
- Net-energy metered solar generation
- Variety of other state policies, programs, and planning decisions

In the statistical analysis, we also explore with less detail: coal plant retirements; degree and type of utility ownership; whether state is part of an ISO/RTO; degree of retail electricity competition; electric vehicle penetration; energy efficiency savings; demand response quantity; advanced metering infrastructure

Organization of content that follows... and summary of findings

- Introduction to how retail electricity rates and prices are established
- Twelve key findings
 - Each finding includes 1-3 slides summarizing data and literature
 - Each indicates what is known, what is likely, and, when applicable, what is not known
 - See top-line findings in list to right
- Statistical analysis
 - Supports core findings by controlling for correlated effects
 - Assesses subset (not all) of the recent price drivers
- Six case studies: CA, ME, ND, FL, VA, PJM
- Summary of drivers of recent state-level trends
- Brief highlights of 2025 developments
- Research, data, engagement gaps
 - Additional research opportunities
 - Key data gaps and limitations

Twelve Findings

1. National-average nominal retail prices have largely tracked economy-wide inflation in recent years, sharply increasing; real prices have been flat
2. Residential customers have faced larger recent price increases than have commercial and industrial customers
3. State-level retail electricity price trends vary widely, with some states' prices rising much faster than inflation
4. Price trends also vary utility-by-utility, with publicly owned utilities generally offering lower prices and experiencing smaller recent price increases
5. Distribution (and transmission) expenditures have contributed to retail price increases, in part due to aging infrastructure and supply-chain constraints
6. Natural disasters, extreme weather, and wildfire mitigation have imposed short- and longer-term costs, significantly increasing prices in some states
7. Natural-gas price fluctuations have been among the largest factors impacting year-to-year variations in retail electricity prices
8. Load growth at the state level has tended to depress retail electricity prices in recent years, by spreading fixed costs over greater load
9. Market-based utility-scale wind and solar deployment do not appear related to recent increases in retail prices; instead, some evidence of price reduction
10. Many state RPS programs have increased retail electricity prices, as expected given the intent of those policies
11. Solar compensated under net energy metering has benefitted adopters while often increasing retail prices, with effects most notable in a small number of states
12. A variety of other state policies, programs, and planning decisions can impact prices, but are not likely to have greatly impacted recent trends in most states

High-level summary of primary drivers of state-level price changes from 2019-2024









Key take away: Many states did not experience outsized price changes in real dollar terms. For those states that did experience such price changes, the drivers were varied and diverse. Based on our analysis and available literature, the largest drivers, at least for subsets of states, are summarized to the right.

Important note: Though many of the past drivers may have similar effects in the future, that need not be true in all cases. National load growth was modest over the time-period of focus for this slide deck but is now accelerating, which may change future price drivers. Tax credits for wind and solar were also available, which have been altered via legislation.

This analysis does not seek to predict future retail electricity prices and related drivers, and nor does it prognosticate on approaches to reduce retail electricity prices.

Key Drivers of State-Level Retail Electricity Price Changes from 2019 to 2024

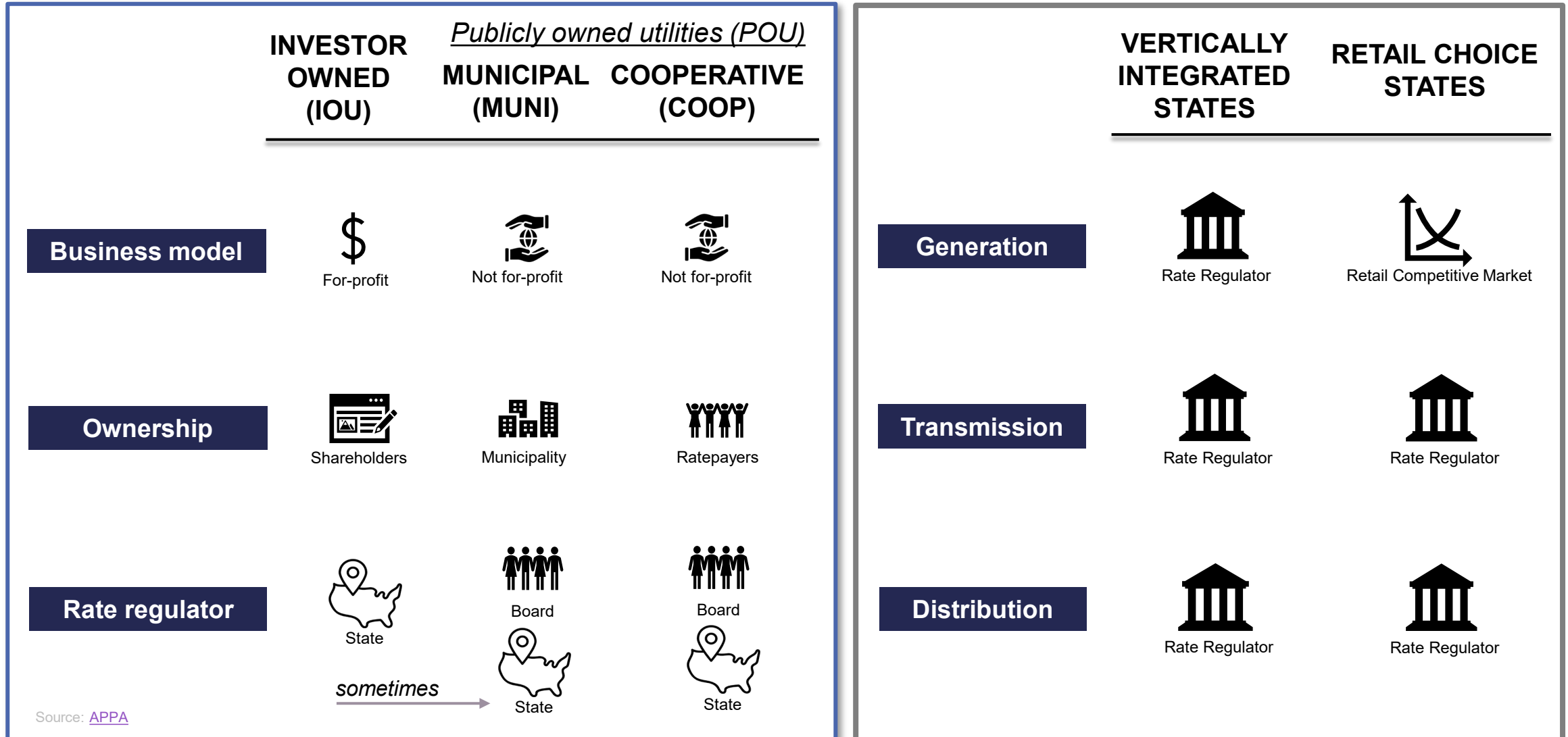
(beyond economy-wide inflation)

Price Driver	Maximum Size	Geographic Breadth	Discussion
Replacement & hardening of aging distribution (and transmission)	 medium	Large	Likely under 0.5 €/kWh in majority of states, but reasonably widespread impact given scale of distribution investments and supply-chain constraints.
Extreme weather & wildfires: recovery and mitigation	 larger	Medium	As much as 4 €/kWh in California, but impacts of 0.5-1.5 €/kWh in a number of states in the West, and on the East and Gulf coasts.
Natural gas price variability	  larger	Large	As much as over 2 €/kWh increase through 2022-2023, with subsequent decrease; most acute impacts in Northeast, NV, FL, PA, etc.
Customer load growth	 medium	Medium	Over 1 €/kWh in only a couple especially high-growth states, with a handful of others over 0.5 €/kWh; relationship may change in future.
Utility-scale wind & solar (market-based)	 medium	Medium	75% of wind and solar growth occurred outside RPS; may have reduced retail prices by over 0.5 €/kWh in a couple states, under 0.5 €/kWh in many others.
State Renewables Portfolio Standard policies	 medium	Medium	As much as ~1 €/kWh in a few Mid-Atlantic and New England states; lower and varied impacts in many other states with RPS programs.
Net energy metered solar	 larger	Small	As much as ~2 €/kWh in California and over 1 €/kWh in small number of other high-growth states especially in the Northeast; low impacts in most states.

Notes: Illustration seeks to show general tendencies. A 'larger' maximum size is defined as an impact of 2 €/kWh or more in at least one state; a 'medium' maximum size is defined as a meaningful but smaller impact of under 2 €/kWh--see the notes column for additional details. A 'large' geographic breadth implies that the price impact may be meaningful among roughly one-third or more of U.S. states, whereas 'small' signifies meaningful impacts in perhaps a handful or fewer states--again, see the notes column for additional details.

Introduction to how retail electricity rates and prices are established

There are 3 major types of utilities, which vary across operating, financial, regulatory, and market dimensions; retail choice is allowed in some states



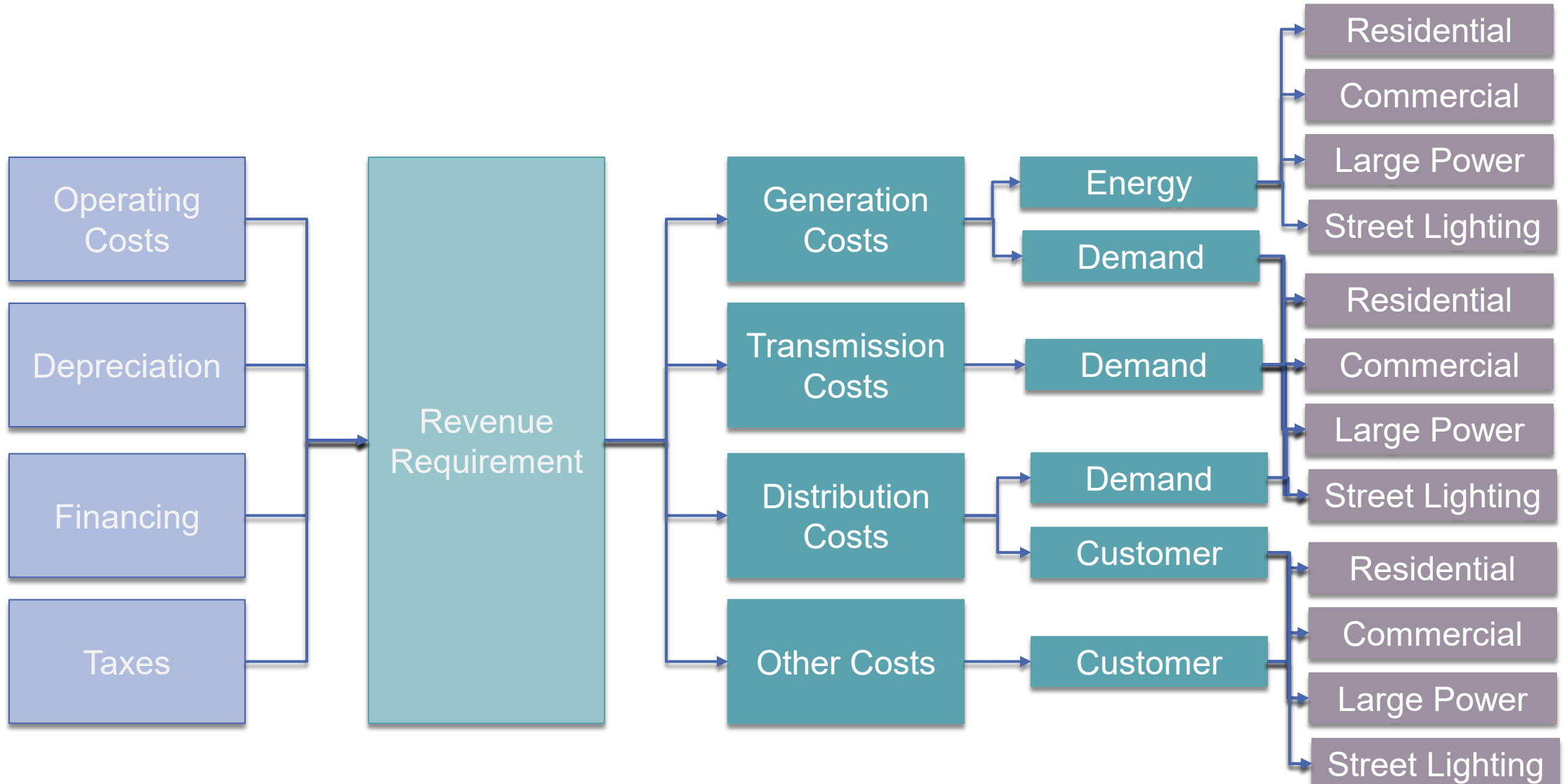
Overview of 'Cost-of-Service' (COS) ratemaking

Regulators approve retail rates that are **reflective of the utility's costs*** to serve retail customers, and that allow a utility an **opportunity** to sufficiently recover those costs

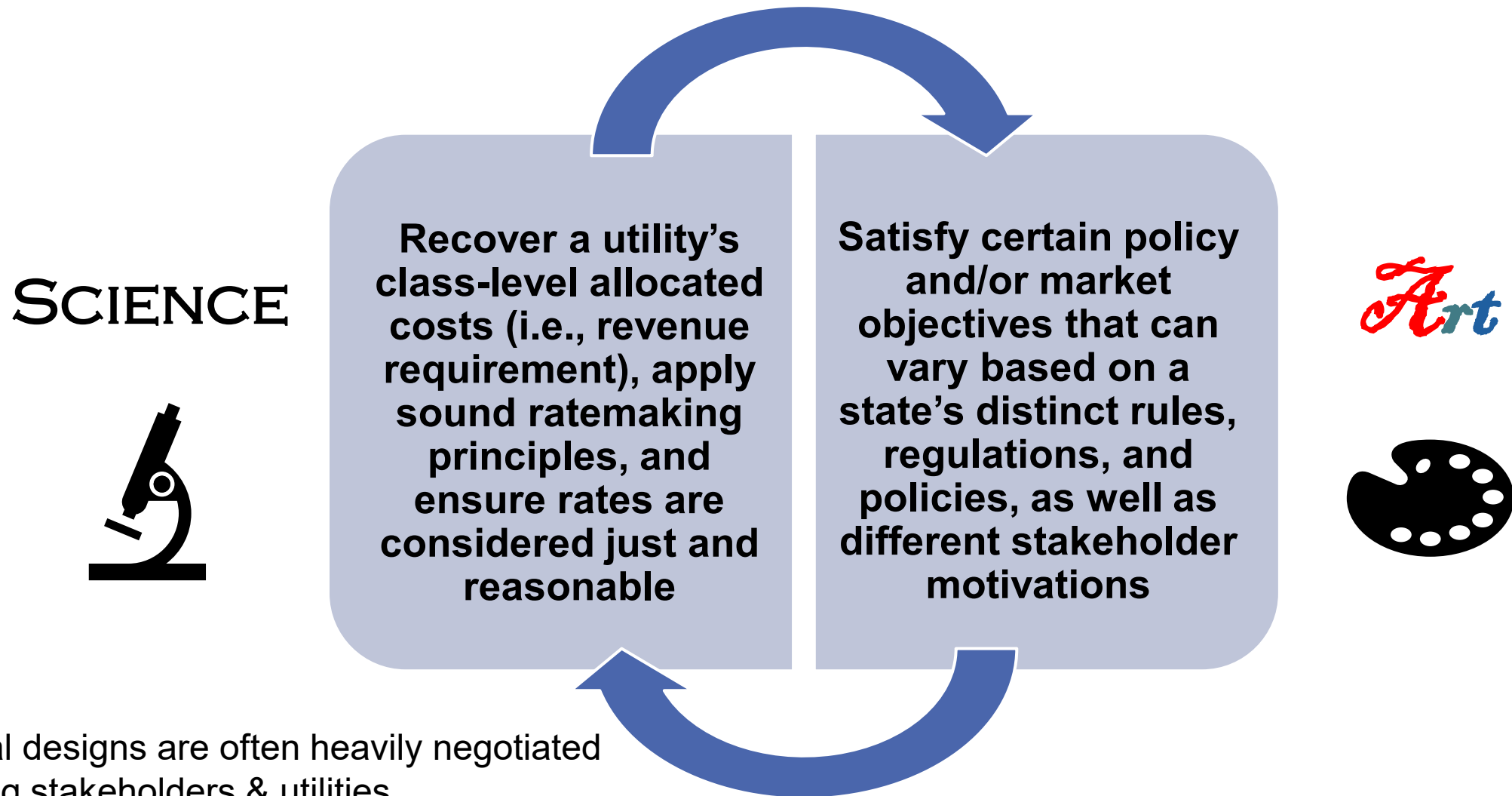
- **Costs** must be deemed to be **prudently incurred** for inclusion in rates
- Capital **assets** are repaid through rates over many years through depreciation and financing, and must be deemed **used and useful** to be put in the rate-base
 - Rates must also give **investor-owned utilities (IOUs)** the **opportunity to earn returns on assets** comparable to what a similarly situated utility would achieve
- **Non-asset-related (e.g. operating) costs** are recovered through rates with no chance to earn return
 - Many non-asset related costs are recovered via base rates set during infrequent rate cases
 - Other non-asset related costs (e.g., fuel and purchased power) are recovered via frequently updated riders & surcharges, with exact treatment varying by state
- Rates must ultimately be deemed **just and reasonable**
- Terminology sometimes differs for POU's vs. IOUs, but principles remain

* In retail choice states, the above requirements do not apply to the **generation component of the rates charged by competitive suppliers**

COS ratemaking seeks to assign utility costs to customer classes and design specific rate structures based on "cost causation" principles



COS ratemaking results in rates designed for each customer class based on two broad concepts*



* Final designs are often heavily negotiated among stakeholders & utilities

Retail electricity rates vs. bills vs. prices

- Utility **retail rates** for end-use customers are comprised of some or all of three kinds of charges:
 - Monthly fixed charges (\$/month)
 - Volumetric energy charges (¢/kWh)
 - Volumetric demand charges (\$/kW-month)
- The composition, levels, and specific designs of these charges differ by utility & customer class
 - Residential, commercial, industrial, street lighting, etc.
- The utility applies these charges to each customer in a class to calculate a **total bill**
- A common metric to represent the overall average **price of electricity** (¢/kWh) is the total collected revenue divided by total retail electricity sales
 - Can be derived at the customer class-, utility-, state-, or national- level

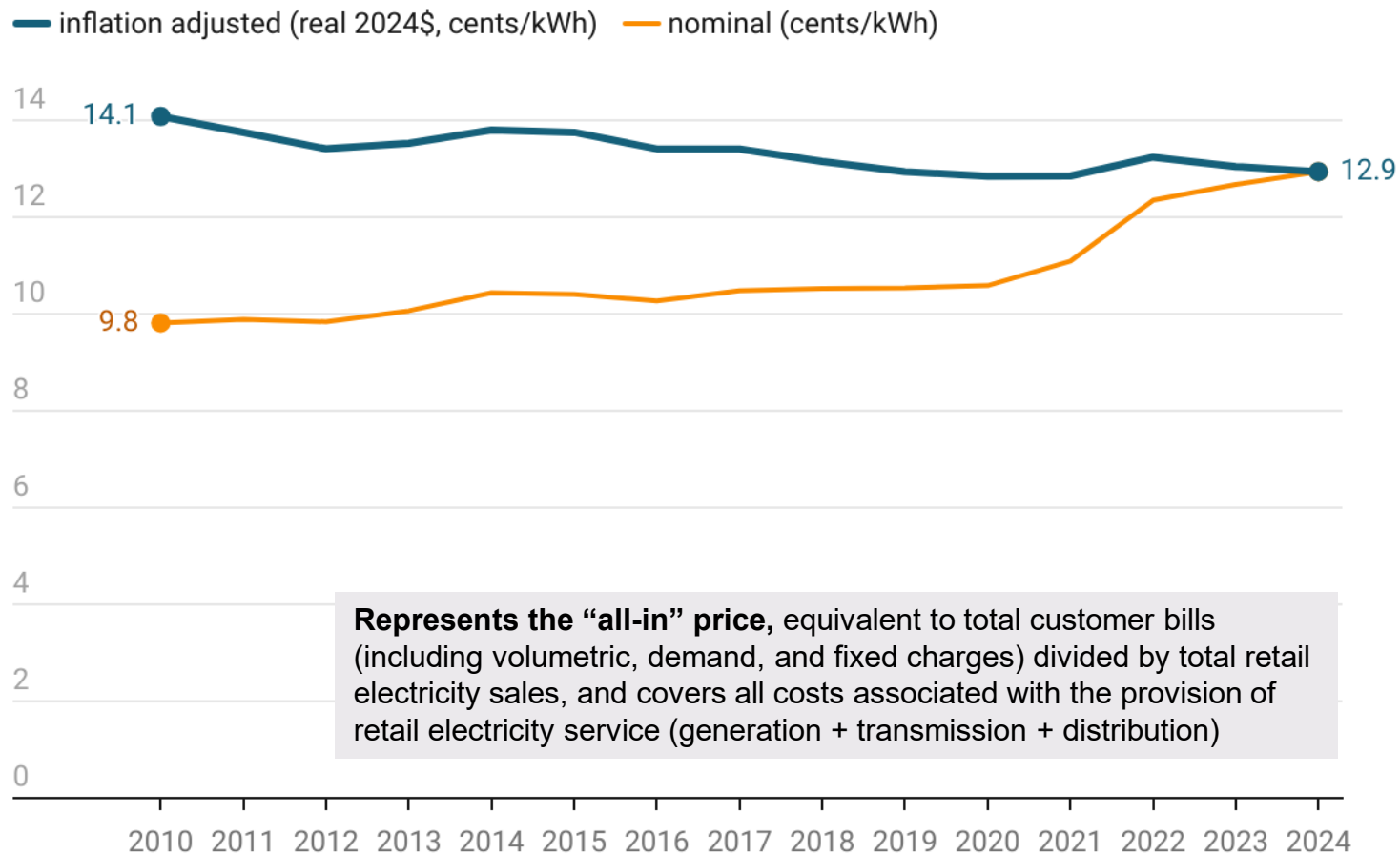
For the remainder of this analysis, we focus primarily on the state-level price of electricity

Twelve findings on retail price trends

National-average *nominal* retail prices have largely tracked economy-wide inflation in recent years, sharply increasing; real prices have been flat

- In nominal (not inflation adjusted) terms, the average retail electricity price **increased by 23% from 2019 to 2024** and 32% since 2010
- When adjusted for inflation, **real prices in 2024 were the same as 2019** and **8% lower than 2010**
- Electricity prices spiked in 2022 at the onset of the Russia-Ukraine war, following natural gas prices
- Bottom line: real prices have declined since 2010; more-recent *national* price escalation tracks overall inflation, but, as per later slides, is outpacing inflation in some states
- *Reminder: Primary focus here and elsewhere is on overall average prices (not just residential)*

National Average Retail Electricity Prices



Source: EIA • Created with Datawrapper

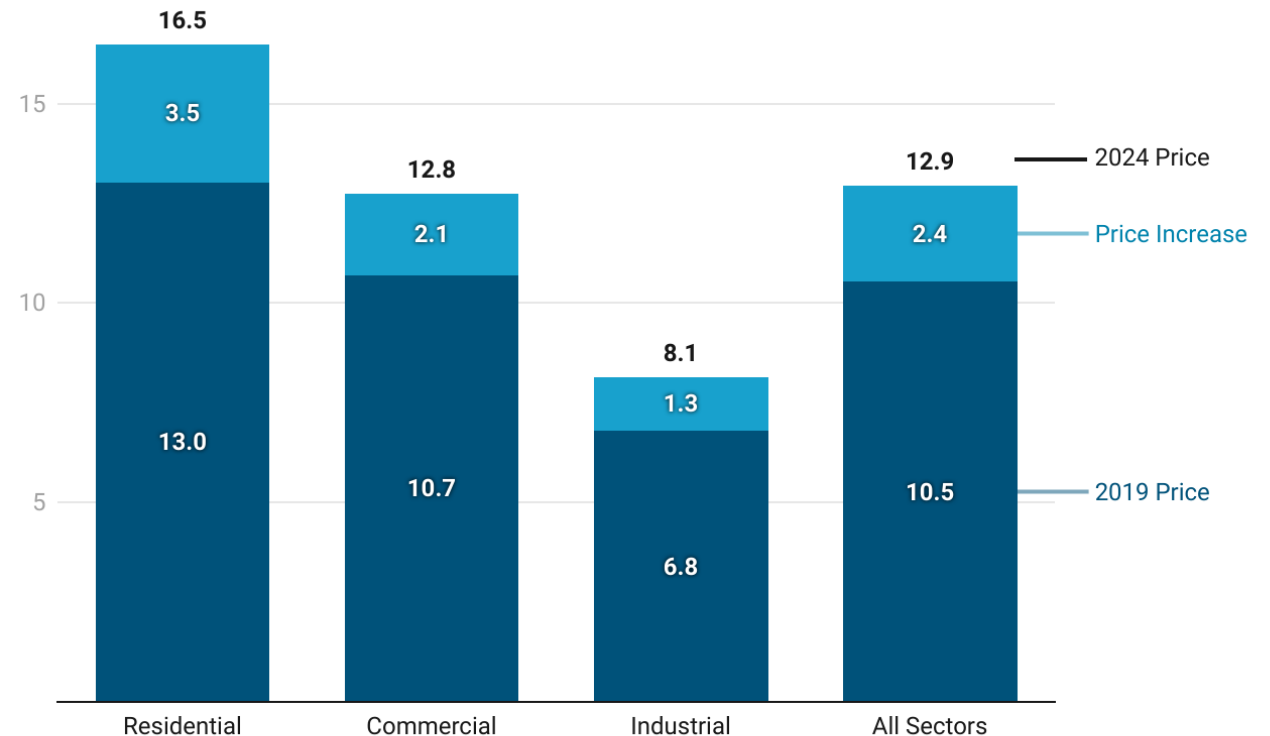
Note: Inflation adjustment uses regional CPI from BLS

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 prices—from 2019 to 2024 (in nominal terms):
 - ▣ Residential prices up: 3.5 cents/kWh – 27%
 - ▣ Commercial prices up: 2.1 cents/kWh – 19%
 - ▣ Industrial prices up: 1.3 cents/kWh – 19%
- Divergence likely due to various factors, which typically occur via state regulation:
 - ▣ Cost to serve smaller customers is generally higher than cost to serve larger customers
 - ▣ Desire by policymakers to support economic development that comes from C&I demand...
 - ▣ ...which is related to strength of advocacy from large C&I customers, inclusive of special rate deals
- *Note: Sectoral price differences vary by state and utility (not shown here)*

Average Nationwide Retail Price by Sector: 2019 and 2024

Nominal cents/kWh (not inflation adjusted)



Source: EIA • Created with Datawrapper

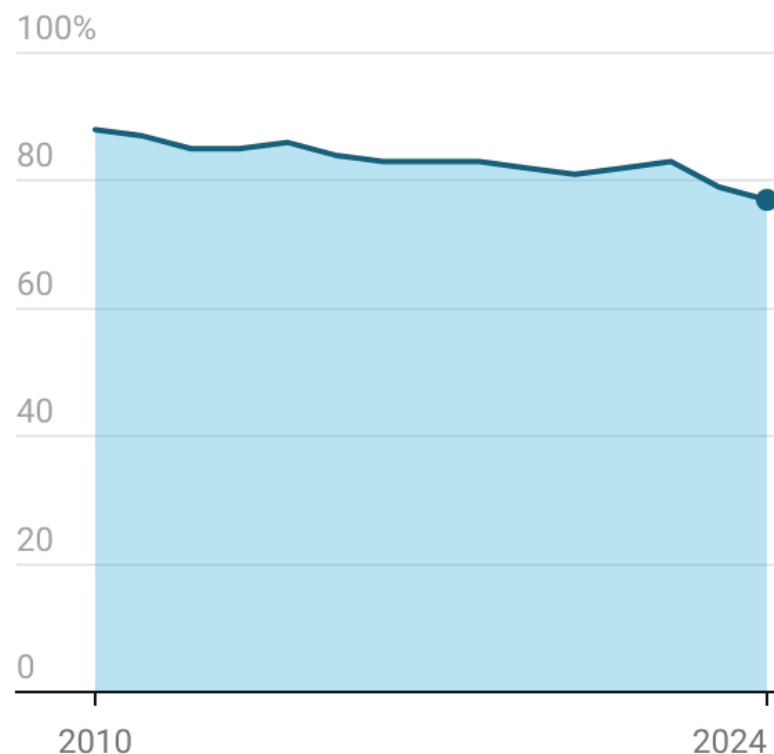
Knowledge Gap: The relative contribution of the three possible drivers for different sectoral outcomes at the national and state level is unclear, as is the resulting degree of effective sectoral cross-subsidization.

Over a longer timeframe, national-average commercial and industrial retail electricity prices have increasingly diverged from residential prices

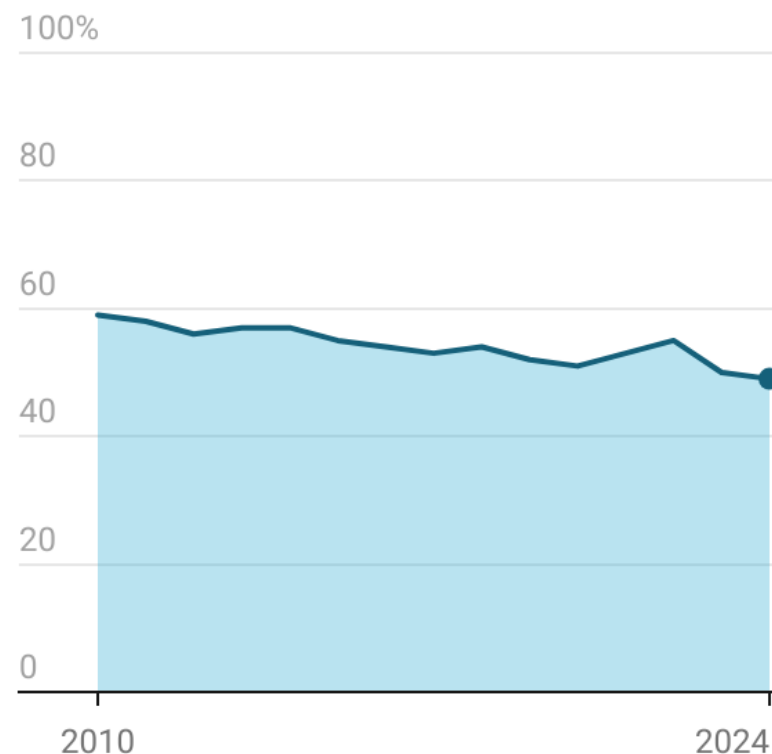
- In 2010, commercial prices were **88%** of residential
 - ▣ By 2024, that percentage had dropped to **77%**
- In 2010, industrial prices were **59%** of residential
 - ▣ By 2024, that percentage had dropped to **49%**
- *Note: Sectoral price differences also vary by state and utility*

National Average Commercial and Industrial Retail Prices Relative to Residential Prices

Commercial prices as a percent of residential



Industrial prices as a percent of residential



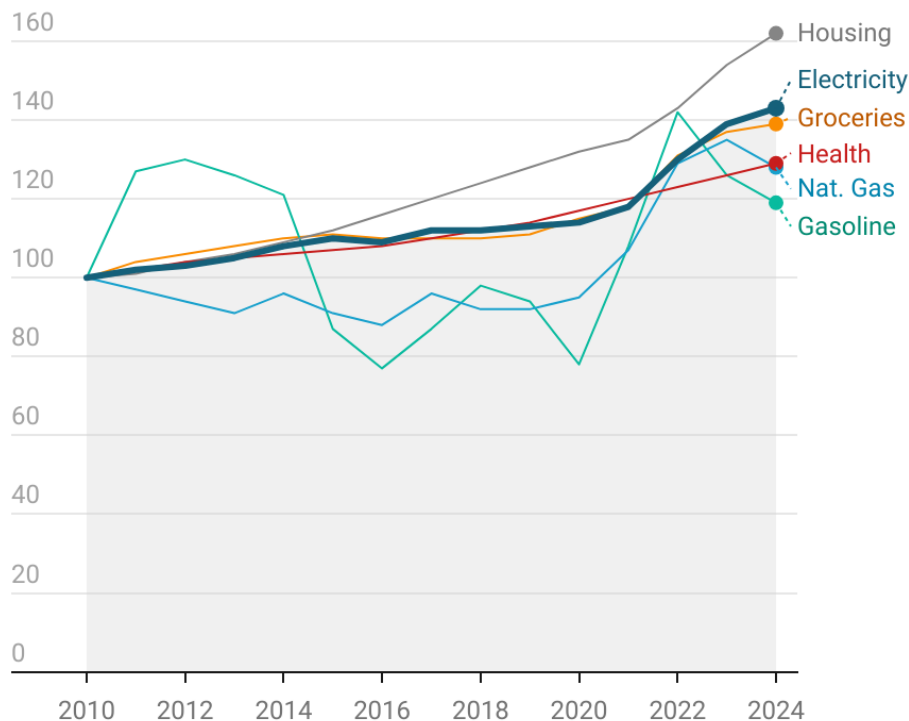
Source: EIA • Created with Datawrapper

Residential price increases have been significant, but inline with many other household expenditures, less volatile than gasoline and natural gas prices

Indexed residential electric prices vs. other household expenditures [not inflation adjusted]: since 2010 (*left, longer term*) and 2019 (*right, shorter term*)

Indexed Prices of Household Expenditures

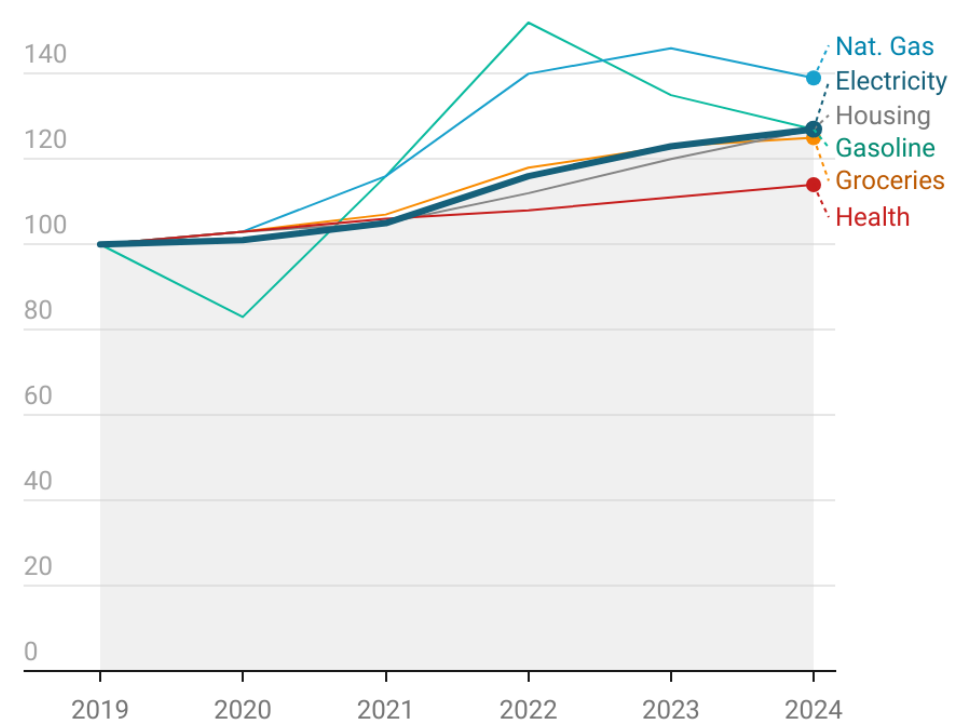
Nominal price index relative to prices and expenditures in 2010



Source: EIA, BEA • Created with Datawrapper

Indexed Prices of Household Expenditures

Nominal price index relative to prices and expenditures in 2019

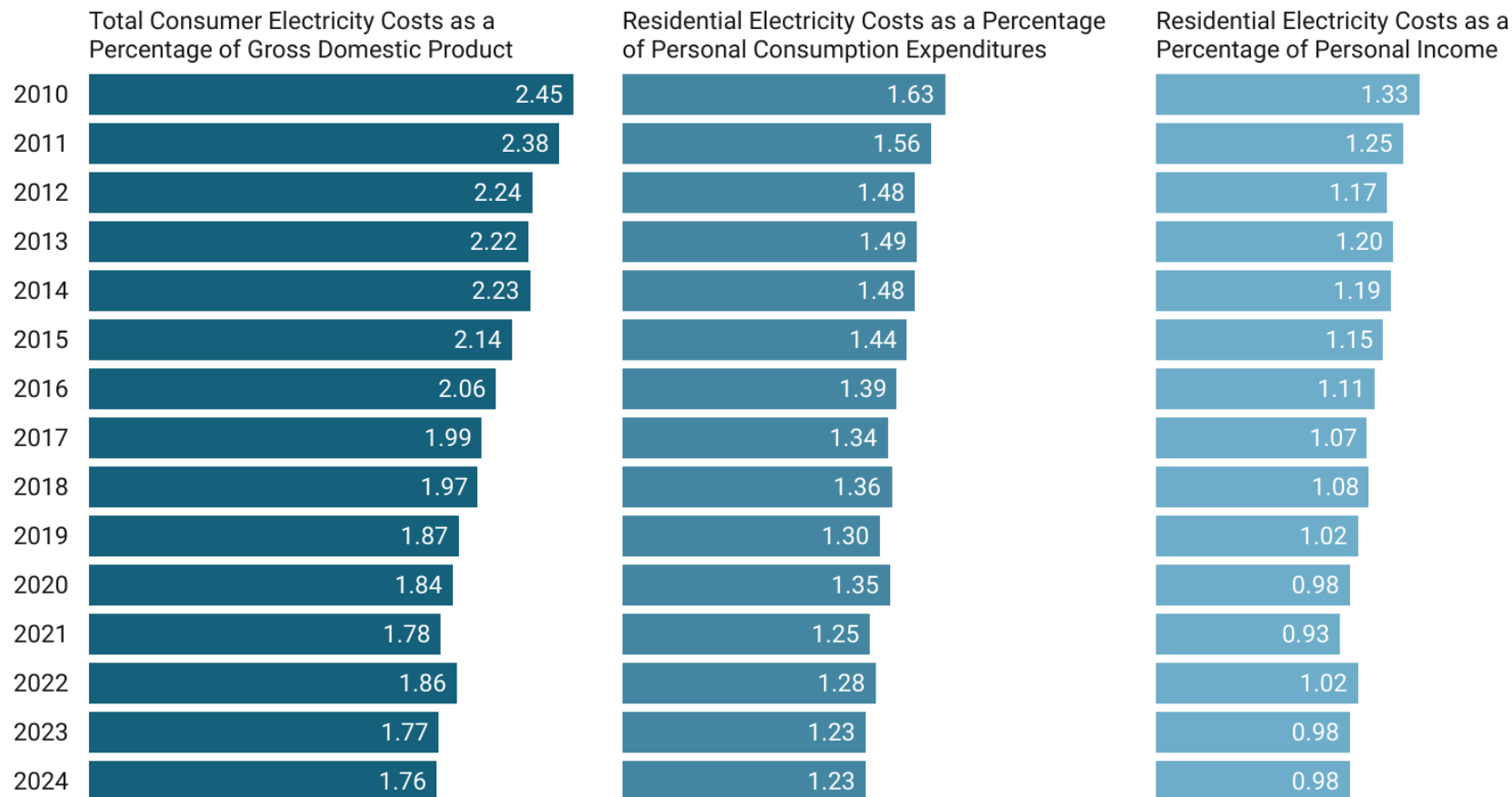


Source: EIA, BEA • Created with Datawrapper

National consumer electricity costs as a fraction of GDP (left graphic) and personal expenditure and income (right two graphics) have trended down

- Consumer electricity costs (aka, bills) are impacted by retail prices and consumption
- Total electricity costs as a fraction of GDP has trended downward for many years, reaching 1.76% in 2024
- Similarly, residential electricity costs as a fraction of personal expenditure (1.23% in 2024) and income (0.98% in 2024) have declined
- Fractions increased in 2022 (tracking natural gas prices), but since declined

Electricity Costs as Fraction of GDP, and Personal Expenditure and Income



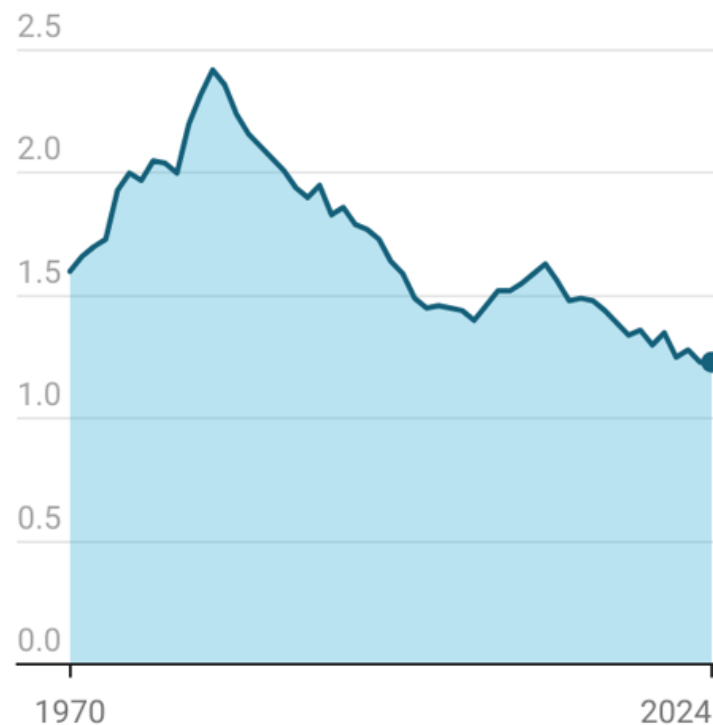
Source: EIA, BEA • Created with Datawrapper

Residential electricity costs as a fraction of personal consumption expenditures (left) and income (right) are at or near all-time lows

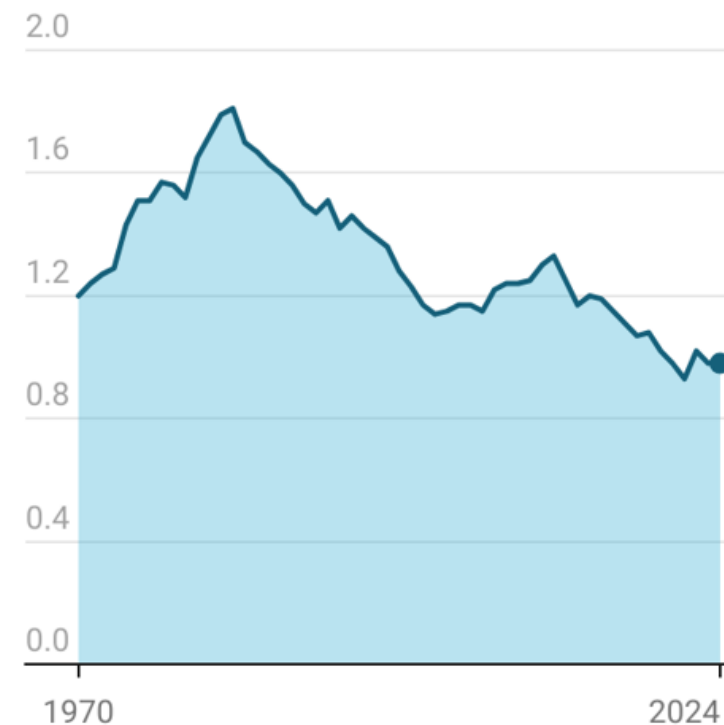
- As a fraction of total personal expenditures and of income, residential electricity bills were at or near all-time lows in 2024
- Fractions increased from 1970 until the early 1980s, then declined until natural gas prices pushed them higher through 2010, and have generally declined since
- Residential electricity bills as a fraction of income was lower in 2021 than in 2024, most-likely a reflection of COVID-19
- Data reflect national averages: some states and households far-more burdened

Residential Electricity Costs as a Fraction of Personal Consumption Expenditures and Personal Income

Residential Electricity Costs as a Percentage of Personal Consumption Expenditures



Residential Electricity Costs as a Percentage of Personal Income



Source: EIA, BEA • Created with Datawrapper

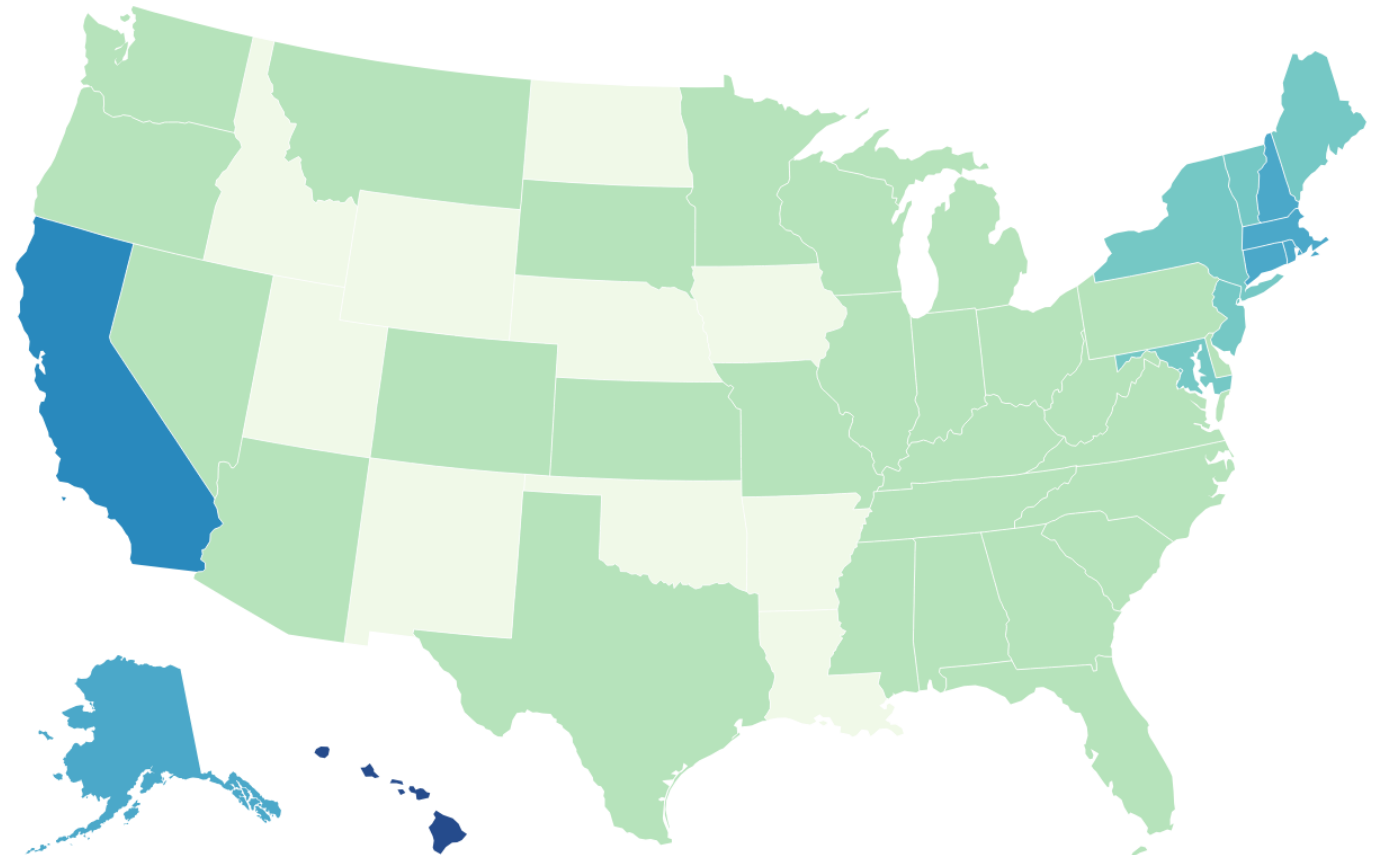
National trends mask stark differences in state-level average retail electricity prices (*this slide*), and recent price trends (*next slide*)

- Average retail electricity prices in 2024 vary widely across states
- Highest prices are in Hawaii, California, the Northeast, Alaska
- Map depicts all-sector average prices, in 2024
- 90% of lower-48 landmass and 75% of U.S. population have all-sector average prices below 15 cents/kWh
- As shown in earlier slide: residential prices are higher, commercial and industrial prices are lower
- Shown later are differences in terms of residential electricity bills, impacted by prices & consumption

Average Retail Electricity Price in 2024

(real 2024\$, cents/kWh)

< 10 10–15 15–20 20–25 25–30 30–35 ≥ 35



Source: EIA • Created with Datawrapper

Recent changes in state-level average retail electricity prices vary widely: figures show inflation-adjusted (*left*) & nominal (*right*) change 2019-2024

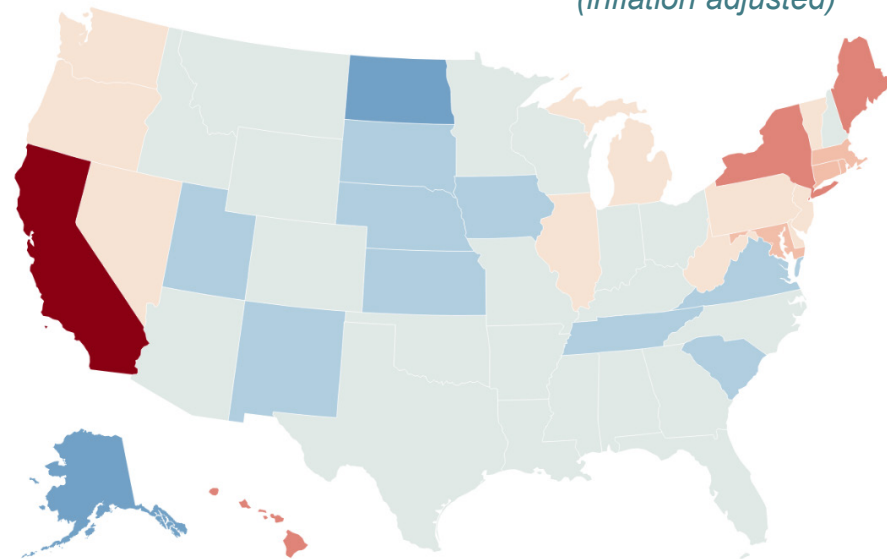
- In inflation-adjusted terms (*left figure*), far more states experienced price decreases than increases
- Without inflation adjustment (*right figure*), nearly all states experienced increased prices: 49 of 50 states
 - California is a notable outlier, with nominal (not adjusted for inflation) average retail prices rising by 10.1 cents/kWh
 - Other states with large increases: Hawaii (9.5 cents/kwh), Connecticut (5.8 cents/kWh), Massachusetts (5.6 cents/kWh), Maine (5.6 cents/kWh), Rhode Island (5.4 cents/kWh), New York (5.3 cents/kWh)

Change in Average Retail Electricity Prices: 2019-2024

Real 2024\$ cents/kWh, inflation adjusted



Real
(inflation adjusted)



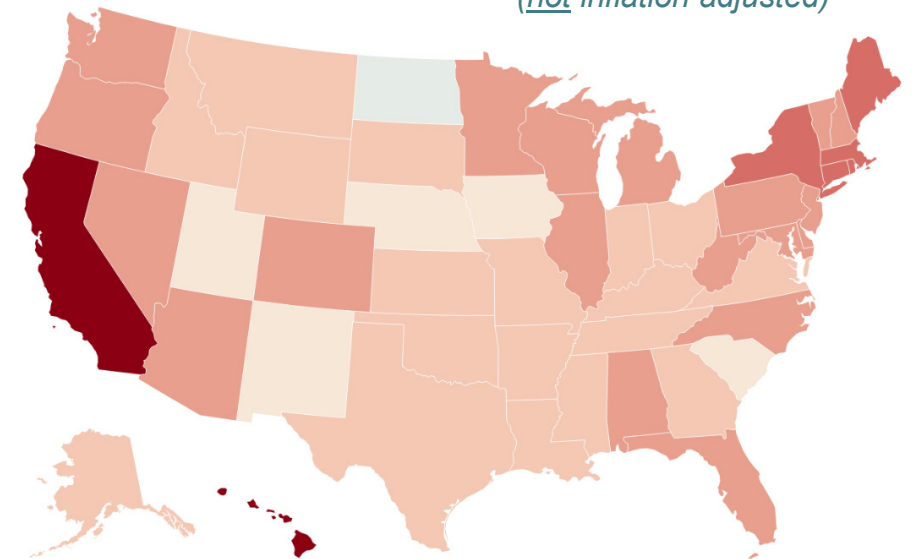
Source: EIA • Created with Datawrapper

Change in Average Retail Electricity Prices: 2019-2024

Nominal cents/kWh, not inflation adjusted



Nominal
(not inflation adjusted)



Source: EIA • Created with Datawrapper

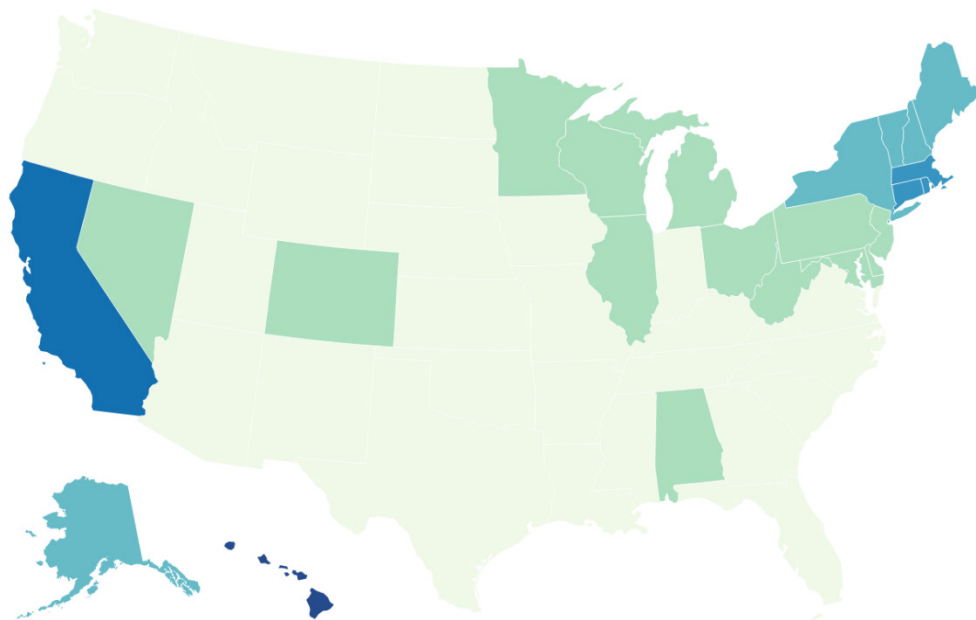
Household affordability is impacted by electricity prices *and* consumption: states with the highest prices (left) may not have the highest bills (right)

- The highest average residential electricity prices in 2024 were in Hawaii, California, the Northeast, and Alaska
- The highest monthly residential electricity bills occurred across a diversity of states; California no longer an outlier
- *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 here¹*

Average Residential Retail Electricity Price in 2024

(real 2024\$, cents/kWh)

< 15 15–20 20–25 25–30 30–35 ≥ 35

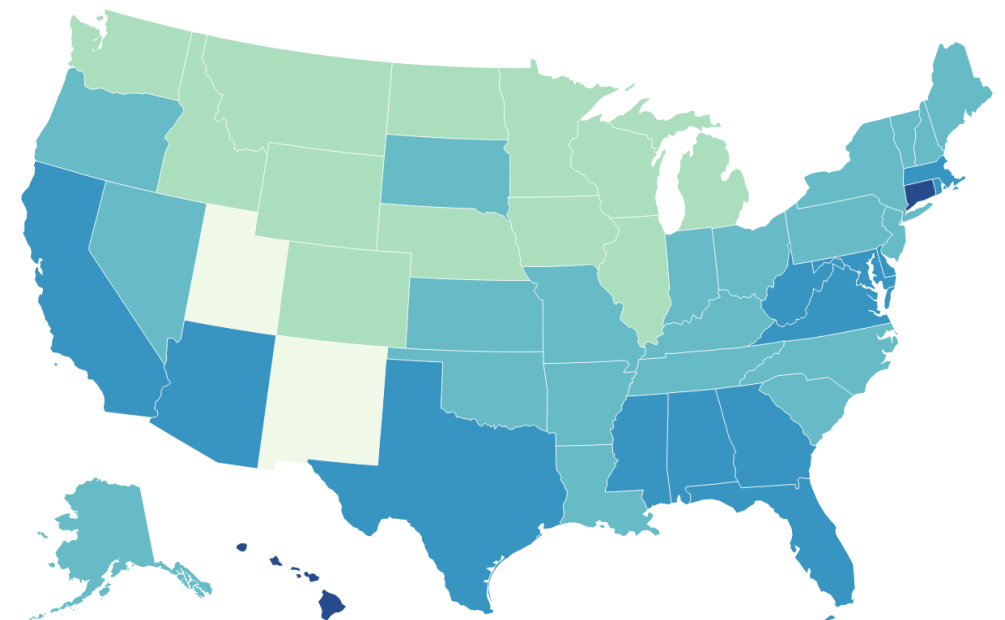


Source: EIA • Created with Datawrapper

Average Residential Monthly Electricity Bill in 2024

(real 2024\$, USD per month)

< 100 100–125 125–150 150–175 175–200 ≥ 200




Source: EIA • Created with Datawrapper

Regardless of overall trends at the national- or state- level, energy expenditures are a major hardship for some households


Household Concerns About Energy Affordability

A look at the financial strain and hardship faced by some U.S. households due to energy costs.


In the Last 12 Months...


 **34%**
of households reduced or forwent basic necessities like food or medicine to pay an energy bill.

 **22%**
kept their home at a temperature that felt unsafe or unhealthy.


 **24%**
were unable to pay an energy bill in full.

In 2024...

 **13%**
of households were behind on their electricity bills.

 **2.7 million**
households had their utility service shut-off due to non-payment.

Looking Ahead to 2025...

 **73%**
of households are very or somewhat concerned that electric and/or gas bills will increase this year.

Sources: U.S. Census Bureau: Household Pulse Survey (2024); NEADA (2024); Powerlines (2025).

Some of these metrics appear to have **improved** over time, whereas others have gotten **worse** (though it depends on the timeframe selected)

Improved since 2019¹

- 17.4 M households were behind on their energy bills in 2024, down from 20 million in 2019

Worse since 2021²

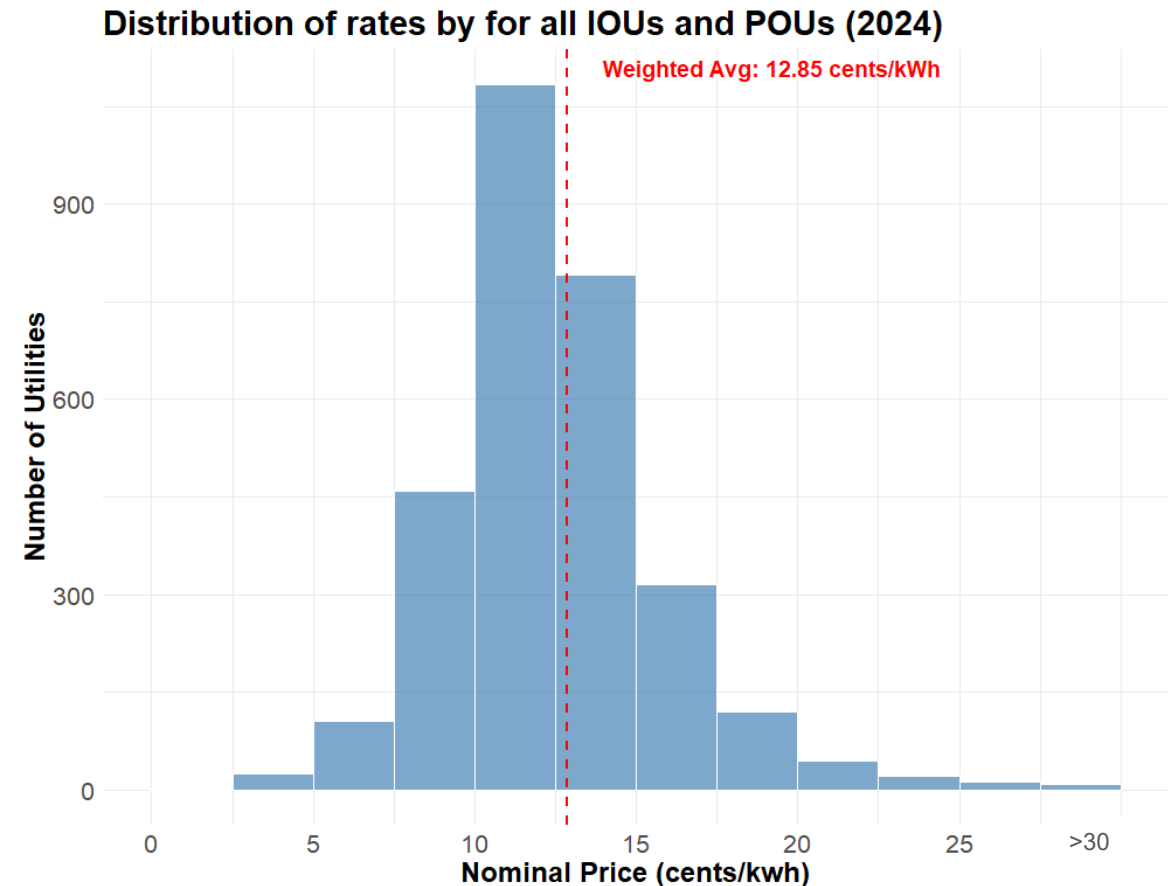
- 34% of households reduced or forwent necessities to pay an energy bill in 2024, up from 29% in 2021
- 22% of households kept their home at an unsafe or unhealthy temperature in 2024, up from 20% in 2021
- 24% of householder were unable to pay their energy bill in full in 2024, up from 20% in 2021

¹ [NEADA Energy Hardship Reports \(2022 & 2024\)](#)

² [US Census Bureau: Household Pulse Survey \(2021 & 2024\)](#)

This study focuses on national and state-level trends, but utility-level retail electricity price trends are diverse

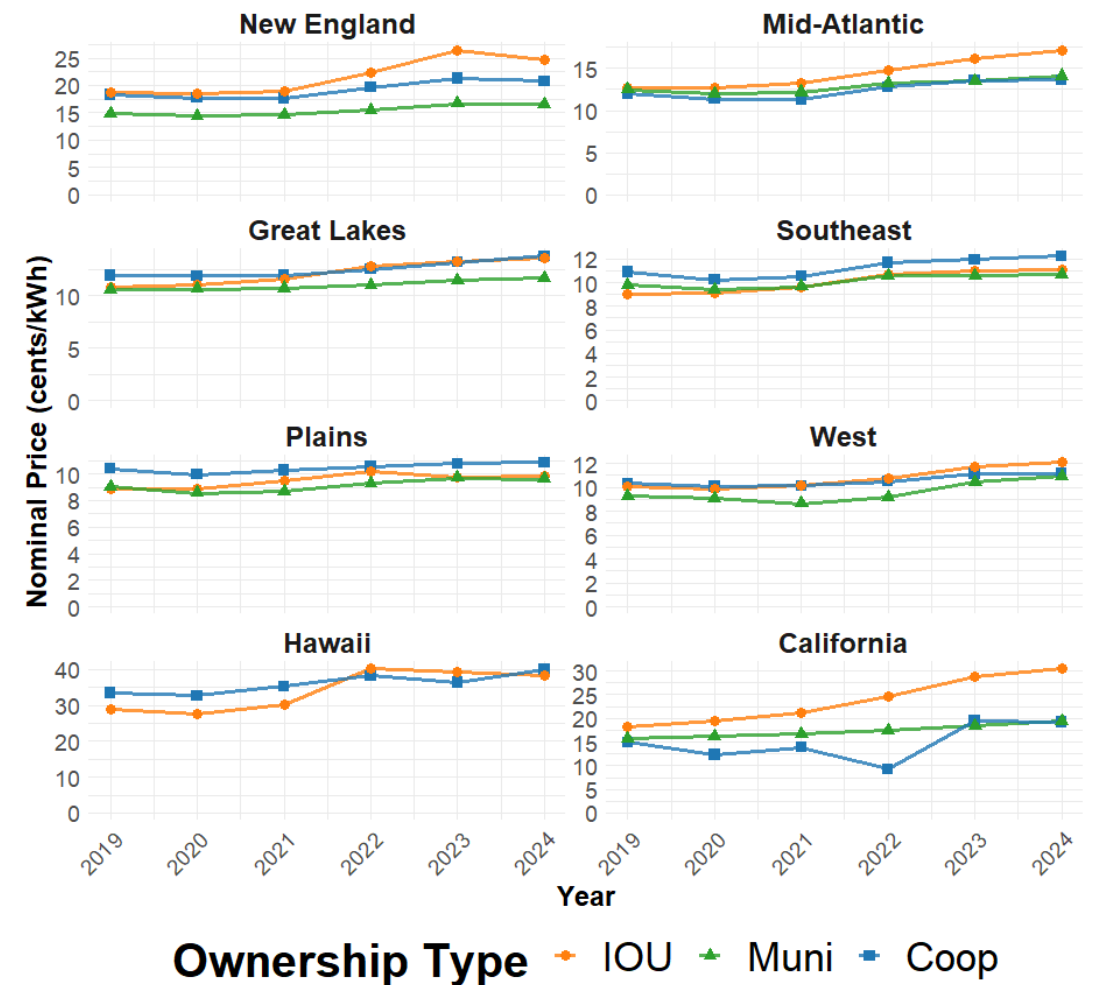
- Figure shows the wide distribution of retail prices across 3,000 utilities in 2024
- Most utilities have average retail electricity prices of 8-17 cents/kWh, with an overall average of 12.85 cents/kWh
- A small minority charge over 20 cents/kWh, mostly among the IOUs; this contributes to higher average prices among IOUs vs. publicly-owned utilities (POUs: Munis and Coops) for some regions, as shown on the next slide
- Not included in the figure are competitive retail suppliers and community choice aggregators; they have average prices that are broadly similar to IOUs, but with a wider overall price dispersion
- Other types of government utilities are also not included (e.g., federal [BPA, TVA] and state); these types tend to offer lower average prices, but do not exist in most states and, where they do, sometimes serve unique customers



Knowledge Gap: Our research focuses on state-level variation in prices, not utility-level variation; there are opportunities for deeper analysis to explain differences among utilities.

Retail prices charged by IOUs have increased faster in nominal terms than those of POUs in many regions of the country

- IOUs experienced greater upward price pressure from 2019 to 2024 in many, but not all, regions
- Whether differences are driven by ownership structure, or other underlying factors, is unclear
- In California, these disparities are partly due to differences in wildfire risk and related costs¹
- Other possible reasons for differences in prices and recent price trends include³:
 - POU access to low-cost debt and federal hydropower
 - Additional income taxes and return on equity for IOUs²
 - State policies that sometimes exempt POUs⁴
 - Differences in characteristics of territories (e.g., size, customer composition, grid / supply networks)
- However, many of the above factors may help explain absolute price differences between IOUs and POUs, but do not obviously explain the divergence between the two utility types over 2019-2024 as shown in the figure



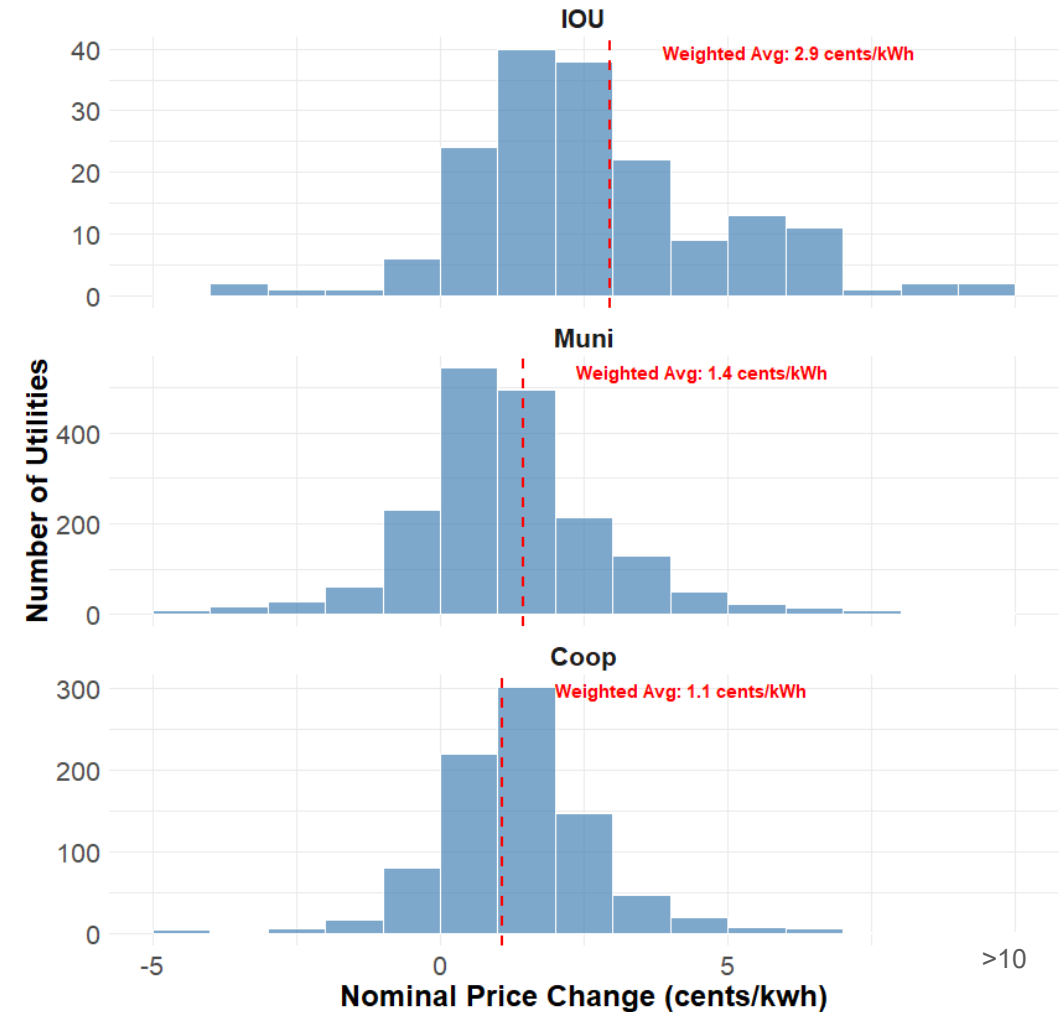
¹ Singh, Ong, and Sud (2025) ² Werner and Jarvis (2025) ³ APPA and NRECA ⁴ LAO (2025)

Regional aggregation on previous slide masks underlying distributions: recent trends are driven in part by a minority of IOUs

- While IOUs have experienced larger nominal (not adjusted for inflation) price increases in recent years, one reason is that a minority of IOUs have experienced outsized increases
- This is illustrated by the right-tail of the IOU histogram distribution shown on this slide
- These outsized increases are especially true for the three major IOUs in California
 - ▣ PG&E, SCE, and SDG&E
- Other IOUs that experienced very large increases over this timeframe include some of the utilities in New England and New York

Knowledge Gap: Disentangle the reasons for differences in retail prices and price trends between IOUs and POUs.

Distribution of rate changes by utility type (2019-2024)



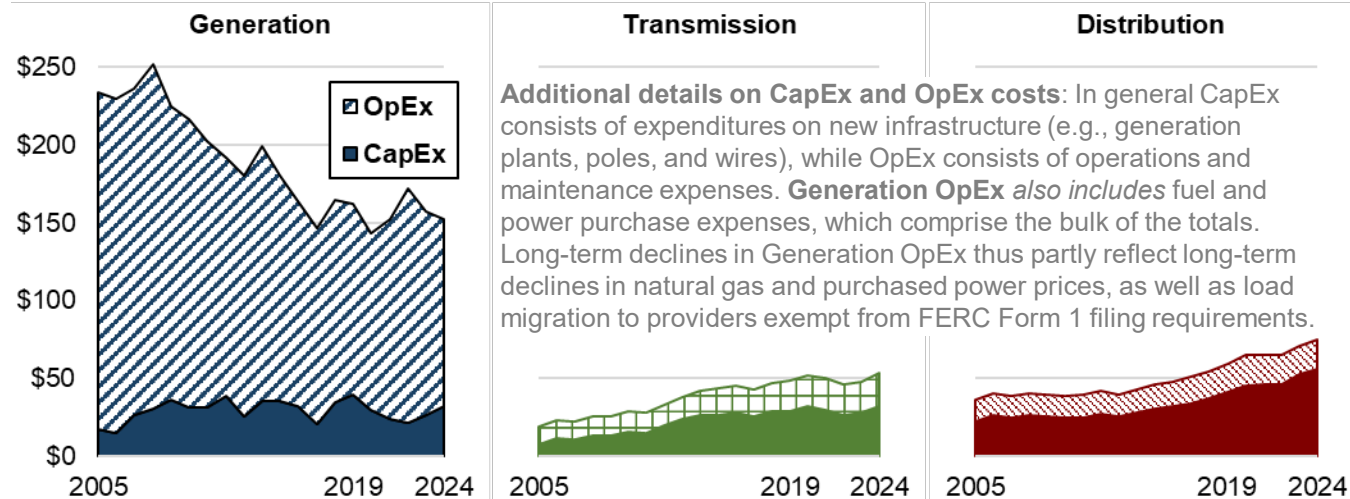
Note: If adjusted for inflation, Munis and Coops had negative weighted-average price changes, while IOU weighted-average price changes remain positive in real terms.

Distribution (and transmission) expenditures have contributed to retail price increases, whereas direct generation costs have declined nationally

- Over the last two decades, aggregate investor-owned utility (IOU) spending on distribution and transmission increased in real, inflation-adjusted terms, whereas expenditures on generation generally declined (left figure)¹
- Focusing on aggregate national IOU data from 2019 to 2024, inflation-adjusted distribution and transmission expenditures increased, whereas generation costs continued to decline (right figure)¹
- Recent growth in distribution expenditures were driven by capital costs (CapEx), which rose 35% in real terms
 - Note: CapEx is often recovered over multiple years and with a rate-of-return, and thus the impacts on retail prices differ from those of operating expenses (OpEx), which are recovered in prices closer to real-time and without a rate-of-return

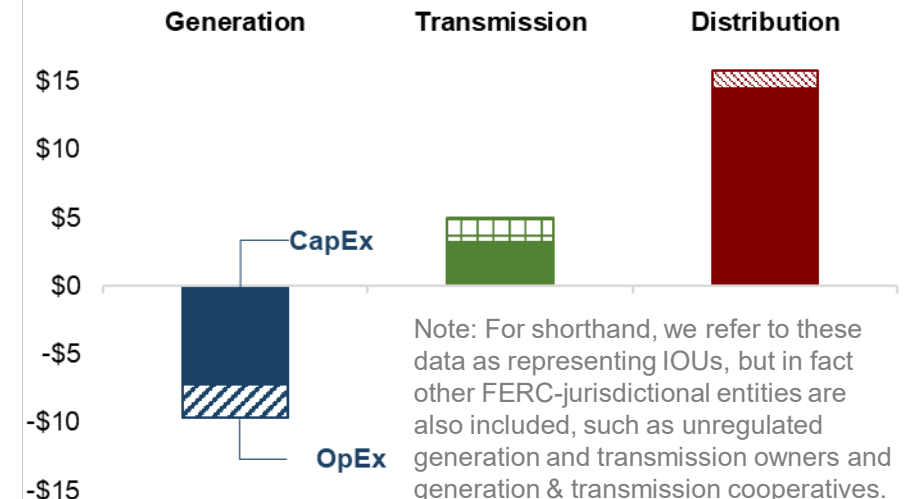
Annual U.S. electric IOU expenditures

billions of 2024 U.S. dollars



2019-2024 change in annual U.S. electric IOU expenditures

billions of 2024 U.S. dollars



¹ Updated analysis of FERC Form 1 data, based on similar methods as in [EIA \(2024\)](#) and [Forrester et al. \(2024\)](#).

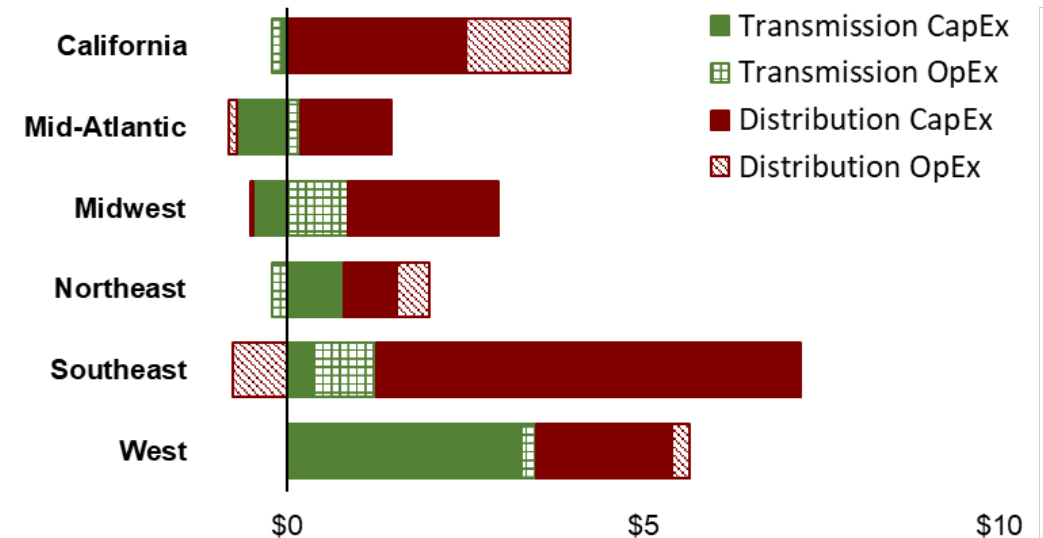
Distribution capital expenditures increased across all regions, but other IOU T&D expenditure trends vary regionally

Focusing on IOU T&D trends¹ from 2019-2024, after adjusting for inflation...

- **Distribution CapEx** rose in all regions, led by the Southeast, where growth is likely partly driven by storm-related recovery and hardening (see later slide)
- **Distribution OpEx** rose notably in California, likely wildfire-related (see later slide), with smaller changes in other regions
- **Transmission CapEx** rose in several regions, most notably in the West, driven by a large PacifiCorp project that entered service in 2024
- **Transmission OpEx** increased in the Midwest and Southeast, but were flat elsewhere; more reflective of year-to-year variability than any persistent trend

¹ We focus here on T&D trends, partly because those are the costs that have risen, nationally, in recent years. In addition, generation cost trends from FERC Form 1 are more prone to misinterpretation, given differences in how and whether those costs are reported, depending on the type of utility. Other elements of this slide deck address generation costs more directly.

2019-2024 change in annual U.S. electric IOU expenditures
billions of 2024 U.S. dollars



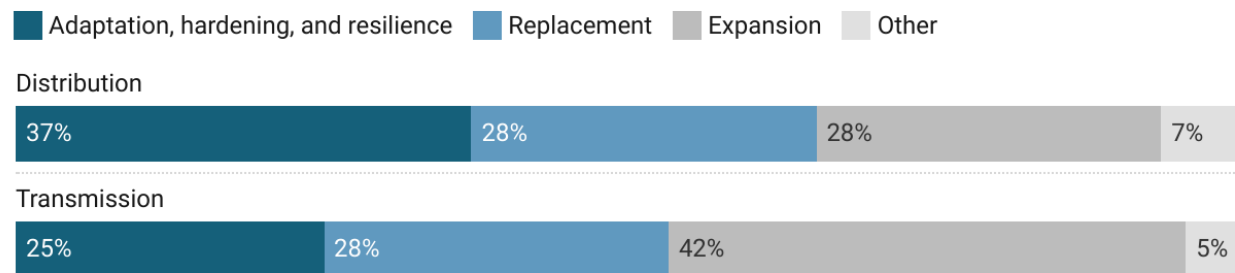
Key caveats for the data and trends above

- Regions vary in size, with potentially large differences in total expenditures
- Most distribution cooperatives and municipal utilities are not included; distribution expenditures are therefore incomplete, to varying degrees depending on the region
- CapEx is lumpy; parsing the data into regions can amplify the volatility when comparing expenses across a given set of years

Recent distribution and transmission costs have been driven by resilience and replacement expenditures, and impacted by supply-chain constraints

- Grid infrastructure is aging—T&D built more than 50 years ago needs to be replaced and modernized
- EEI companies report that **65% of their distribution** and **53% of their transmission** investment is driven by **replacement** or **adaptation, hardening, and resilience** initiatives; rest is expansion or other¹
 - ▣ Brattle estimates >\$10 billion/year is now spent annually for the replacement of aging transmission infrastructure²
 - ▣ FERC data show that very few new, large-scale transmission lines have been built over the last 5+ years³
 - ▣ Recent growth in distribution costs have been driven by poles, towers, undergrounding, and line transformers⁴
- **Supply-chain for T&D has been tight since COVID**; costs have risen far above inflation (right figure)⁵

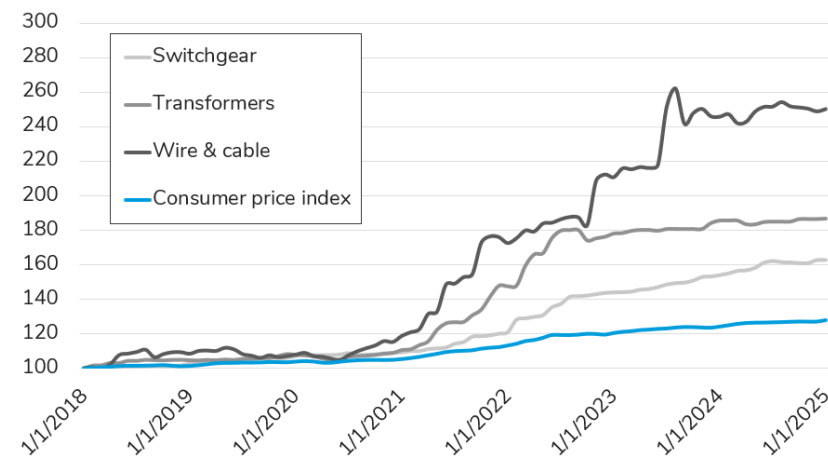
Drivers of Distribution and Transmission Investment



Source: EEI • Created with Datawrapper

Knowledge Gap: We do not fully understand the relative proportion of different drivers for these costs, and how that varies by state

Producer price index for critical power system equipment, St. Louis Fed



¹ [EEI \(2024\)](#) ² [Brattle \(2025\)](#) ³ [FERC \(2025 & earlier\)](#)

⁴ [EIA \(2024\)](#) ⁵ [Lubershane \(2025\)](#)

Natural disasters, extreme weather, and wildfire mitigation have imposed short- and longer-term costs, significantly increasing prices in some states

Natural disasters, extreme weather, and wildfires can raise retail electricity prices in two ways:

- **Reactive**, shorter-term capital and operating costs to recover and rebuild immediately following a disaster
 - *Likely often in the “replacement” category on the previous slide*
- **Proactive**, longer-term infrastructure hardening, operational practices, insurance to protect against future risks
 - *Likely in the “adaptation, hardening and resilience ” category on the previous slide*

Impacts on retail electricity prices can be temporary or longer-term, depending in part on whether costs are related to immediate recovery or long-term risk reduction, but also:

Whether costs are related to CapEx (longer-term amortization) or OpEx (shorter-term passthrough)

Whether costs are part of a balancing account for possible future recovery after a general rate case

Whether regulators allow securitization or other measures to spread costs over longer timeframes

Reactive utility investments to recover from natural disasters and extreme weather have had significant retail price impacts in some states

- Damage to utility infrastructure from extreme weather leads to immediate repair costs, which are recovered from customers in the form of higher electricity prices
- The magnitude of the costs can fluctuate, influenced by the frequency and severity of extreme weather events as well as the resilience of the utility's system: East and Gulf coast states have experienced disproportionate impacts
- Price impacts can be temporary or long-term, depending on regulatory treatment, whether the costs are CapEx or OpEx, and whether securitization is used
- The scope of natural disasters and varying rate recovery makes it challenging to identify trends, as data are dispersed across multiple events, utilities, and jurisdictions
- In Florida, damage from Hurricane Debby, Helene, and Milton in 2024 resulted in 1- to 1.5- year residential price increases from 1.2 to 3.2 cents/kWh in 2025
- Central Maine Power's storm recovery costs grew from ~0.1 cents/kWh at the end of 2020 to ~1.8 cents/kWh at the end of 2024 (and 3.2 cents/kWh at end of 2025)

Recent Estimates of Utility Storm Recovery Price Impacts

Price estimate represents actual or likely impact on (mostly) residential retail prices in year shown, but some cost recovery mechanisms are short duration (i.e., the reported impact is temporary) whereas in other cases costs are securitized and the reported price impacts will persist for as many as 20+ years. Normalized 1-year cost estimates represent the total costs recovered over the recovery period divided by one year's of retail sales, and reflect the retail price impact that could occur if costs were recovered in a single year. Data are imperfect and should only be used to illustrate the wide range of and significant impacts. Includes recent estimates for only a subset of utilities.

Utility	State	Year	Duration	Price impact (cents/kWh)	Normalized 1-year cost (cents/kWh)
Duke Energy Florida	FL	2025	1-year	3.2	3.2
Central Maine Power	ME	2025	2-years	2.4	3.1
Tampa Electric Company	FL	2025	1.5-years	2.0	3.0
Entergy Louisiana	LA	2025	15-years	1.4	20.0
Florida Power & Light	FL	2025	1-year	1.2	1.2
Eversource	CT	proposed	6-years	1.1	6.4
NYSEG	NY	2025	6-11 years	1.1	9.6
Central Florida Electric Coop.	FL	2025	temporary	0.9	1.4
SWEPCO	LA	2025	14-years	0.6	9.0
Duke Energy Progress	SC	2025	20-years	0.5	10.0
Oncor	TX	proposed	long-term	0.5	0.6
Duke Energy Carolinas	LA	2022	9-20 years	0.5	7.6
Centerpoint	TX	2025/proposed	15-years	0.3	3.8
Duke Energy Progress	NC	2022	20-years	0.2	4.9
Entergy Texas	TX	2022	15-years	0.2	3.4
PSE&G	NJ	2025	long-term	0.2	0.4
Portland General Electric	OR	2023	7-years	0.1	0.8
Duke Energy Carolinas	NC	2022	20-years	0.1	1.0

Source: LBNL • Created with Datawrapper

Knowledge Gap: There is no comprehensive synthesis of these costs. As such, it is not entirely clear to what degree these costs are—on average—increasing over time, or whether they mostly impact price variability.

Proactive, longer-term investments to mitigate wildfire risk have been a significant driver of retail price increases in some states

- Proactive infrastructure hardening and operational expenses to protect against future natural disasters, extreme weather, and wildfire risks are common; especially for wildfires, utility liability for damages and related insurance are also sizable, and credit rating downgrades can further impact retail prices
- Wildfire risk mitigation and liability costs were modest until recently but have been a major driver of recent retail price increases in some Western states
- From 2019-2023, California's three large IOUs were authorized to include \$27 billion in wildfire-related costs in retail prices (60% for mitigation, 40% for liability insurance)¹; as of June 2024, wildfire-related costs comprised an average of 17% of total IOU revenue requirements²—up from 1.7% in 2019 and, if directly translated into one-year cost impacts, equivalent to a 4 cents/kWh increase
 - California is somewhat unique due to a history of utility-caused wildfires and specific liability rules³
- Other Western utilities also have significant recent or planned wildfire mitigation (and insurance & liability) costs, as shown in selected examples in figure
- Data in figure are examples and not entirely comparable; data are also not necessarily equivalent to a retail price impact in any specific year given the common practice of spreading costs over multiple years (especially CapEx)
 - Note also that many of the data points include only a subset of the cost impacts of wildfires

Knowledge Gap: There is no comprehensive, comparable synthesis of these costs (though see PNNL database for mitigation plans⁴, excellent PNNL summary and synthesis⁵, and Stanford paper⁵)

¹ [Sieren-Smith et al. \(2024\)](#), ² [The Public Advocates Office \(2025\)](#), ³ [LAO \(2025\)](#), ⁴ [PNNL \(2025\)](#), ⁵ [PNNL \(2025\)](#) ⁶ [Macomber et al. \(2025\)](#)

Recent Estimates of Utility Wildfire Mitigation Costs

Includes estimates for a subset of electric utilities. As per note below, data shown are not always equivalent to retail price impact, and are not fully comparable with one another.

Utility	State	Equivalent cost impact (cents/kWh)
PG&E	CA	7.0
SDG&E	CA	3.0
SCE	CA	2.6
KIUC	HI	1.7
Hawaii Electric	HI	1.5
PSCo	CO	1.4
Rocky Mountain Power	UT	0.8
Pacific Power	OR	0.7
Rocky Mountain Power	WY	0.6
PGE	OR	0.6
AEP Texas	TX	0.5
Northwestern	MT	0.5
APS	AZ	0.4
Idaho Power	ID	0.3
Avista	WA	0.2
Nevada Power-North	NV	0.2
Oncor	TX	0.2
Nevada Power-South	NV	0.2
PNM	NM	0.1
PSE	WA	0.1
SPS	TX	0.1

Cost estimates are recent (e.g., 2024-2025) or projected (2026-2028), and normalized by retail sales. Data do not always equate to retail prices, and are not fully comparable given different scopes (e.g., liability insurance is only included in a subset), tariff surcharges vs. balancing accounts, vs. revenue requirements, different mixes of CapEx and OpEx, etc. Data should therefore only be used to illustrate wide range of and significant impacts.

Source: LBNL • Created with Datawrapper

Natural-gas price fluctuations have been among the largest factors impacting year-to-year variations in retail electricity prices

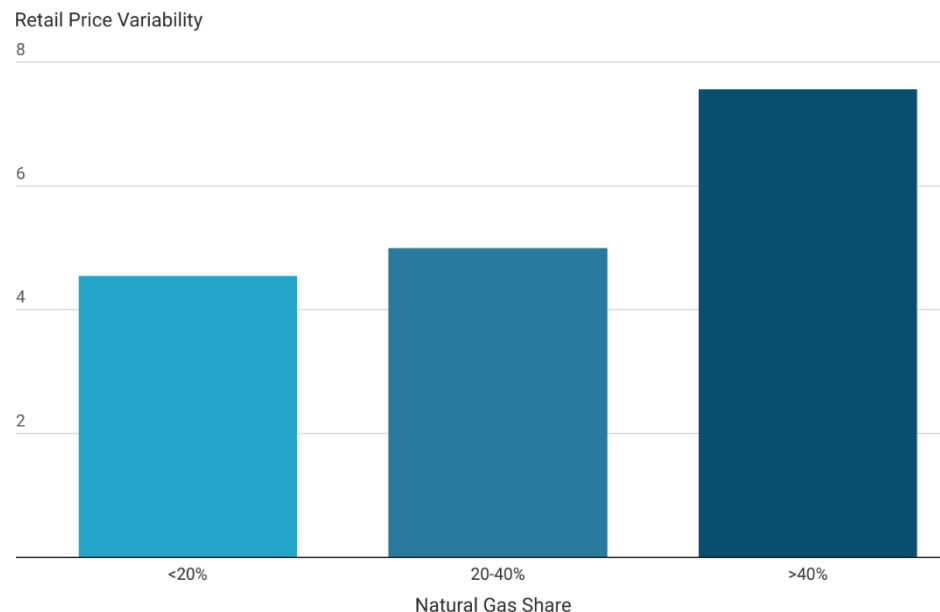
- Natural gas accounts for a substantial share of U.S. electricity generation (43% in 2024), and that share has dramatically increased in recent decades, reflecting its economic competitiveness and ability to reduce retail prices over time
- However, natural gas prices are variable, and fluctuations have long been known to flow through to wholesale and retail electricity prices¹ – in terms of retail prices, C&I customers often experience more-immediate passthrough of price impacts
- The effect of natural gas prices on retail electricity prices in each state depends on: the degree of reliance on natural gas, the presence of pipeline constraints, the extent to which generators or utilities hedge fuel purchases, participation in wholesale power markets, the degree of utility ownership of gas plants, and any lag in passing through costs to end-use consumers
- Notwithstanding these complexities, the chart on the right shows that states with higher shares of natural gas experience, on average, more year-to-year variability in retail electricity prices
- The next slide presents a case study of the impact of the onset of the Ukraine-Russia war, which temporarily increased gas prices globally and domestically
- Statistical analysis (some presented later) confirms these trends

Knowledge Gaps: What makes certain states more-susceptible to these impacts, and what are the advantages and disadvantages of various regulatory approaches to reduce the impacts on end-use customers?

¹ See [Ohler, Mohammadi, and Loomis \(2020\)](#) and [Alexopoulos \(2017\)](#)

Natural Gas Share vs. Retail Price Variability: 2010-2024

Retail electricity price variability calculated as state-average coefficient of variation of annual prices from 2010-2024. Natural gas share presented as average state share of total generation over same period.



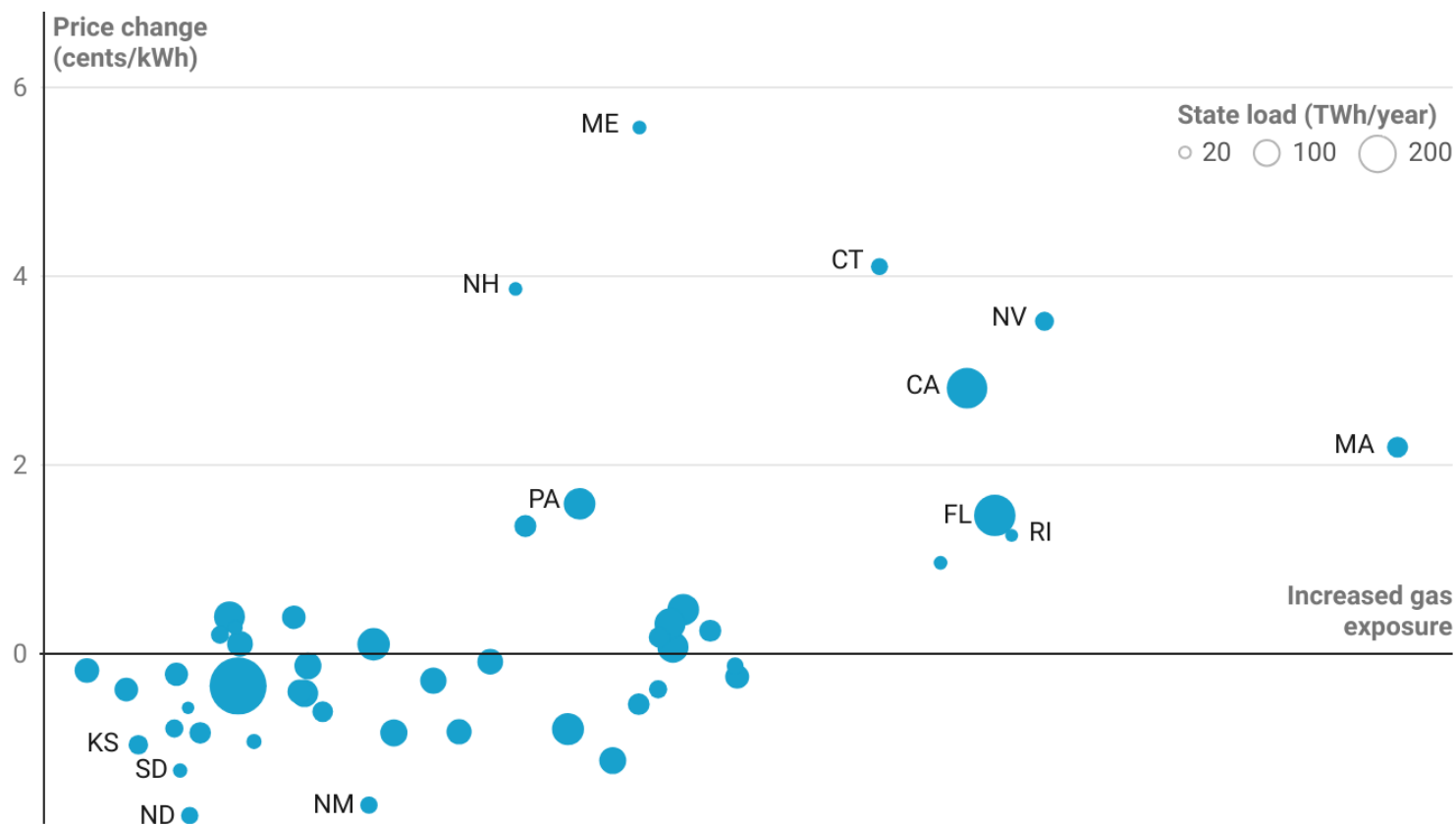
Source: EIA • Created with Datawrapper

Case study example: rise in retail electricity prices after the onset of the Ukraine-Russia war

- Chart shows how state-level exposure to natural gas prices impacted retail electric prices over brief period: 2021-2023 (note: some states experienced larger impacts through 2022)
- Gas exposure is defined as a combined impact of state-level natural gas share and state-level gas prices (reflective of pipeline constraints)
- Outliers exist and price changes were driven by multiple factors beyond gas, but there is a clear relationship between gas exposure and price increases, with impacts as high as or even greater than 2 cents/kWh
- Note:* some states with the largest increases through 2022-2023 also had the largest decreases in 2024 vs. 2022 or 2023 as gas prices moderated: NH (-3.1 cents/kWh), LA (-2.5), NV (-2.0), ME (-1.9), OK (-1.7), FL (-1.4)

Natural Gas Exposure vs. Retail Price Changes from 2021 to 2023

Price change in cents/kWh, inflation adjusted to 2024\$. Gas exposure defined as state-level share of natural gas multiplied by change in state's hub-level gas prices (in \$/MWh) from 2020-21 to 2022-23.



Source: EIA, ABB Ventyx • Created with Datawrapper

Note: Graphic shows prices in real 2024\$; but relationships are the same if shown in nominal terms

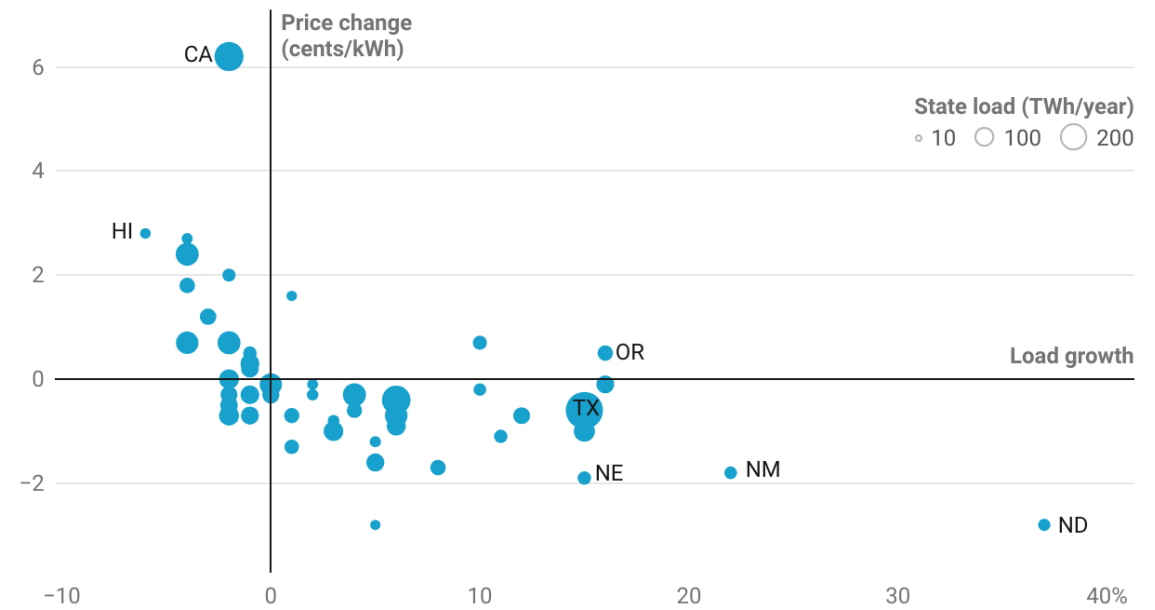
Load growth at the state level has tended to depress retail electricity prices in recent years, by spreading fixed costs over greater load

- Forecasted load growth from data centers, manufacturing, and other drivers has created concerns that increasing load might place upward pressure on wholesale prices and T&D delivery infrastructure, and thus also retail electricity prices¹
- Over the last 5 years, however, states with the highest growth saw average prices decline in inflation-adjusted terms (over 1 cent/kWh in some cases); states with load reduction / contraction often saw prices increase
- Statistical analysis by LBNL presented later confirms this finding, controlling for other variables
- Recent cost increases have not primarily been due to load growth²; it is therefore natural that load growth over this period tended to reduce prices as fixed costs are spread over more demand (and the reverse for load reductions)³
- Quotes from [Georgia](#), [California](#), [Maine](#) support concept of load growth potentially putting downward pressure on prices
- Importantly, this relationship need not always exist: a higher growth future can increase retail prices if new supply and delivery infrastructure is constrained and costly—as it currently appears to be in some or many states**

Knowledge Gaps: Under what conditions does load growth increase vs. decrease prices; what is the future likelihood of those conditions?

Load Growth vs. Retail Price Changes from 2019 to 2024

Price change in cents/kWh, inflation adjusted to 2024\$. Load growth in percentage terms from 2019 to 2024.



Source: EIA • Created with Datawrapper

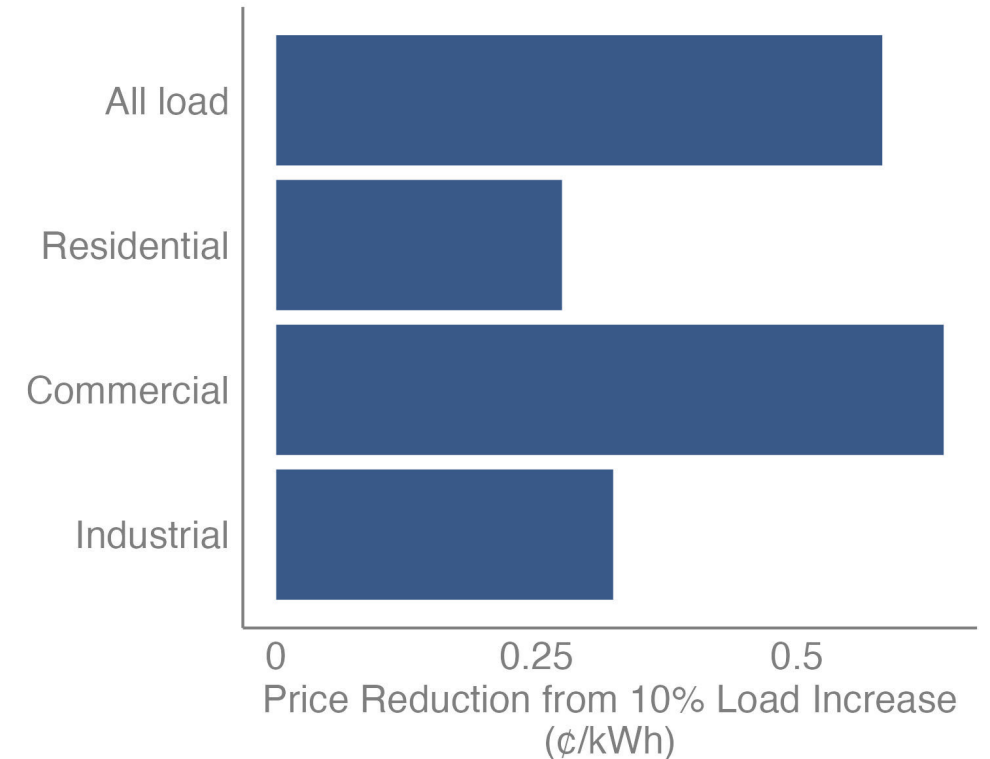
Note: Graphic shows prices in real 2024\$; relationships are the same if shown in nominal terms

¹ e.g., [Chandramowli et al. \(2024\)](#), [EIA \(2025\)](#)

² [Forrester et al. \(2024\)](#) ³ [Fares and King \(2017\)](#)

The price-reducing impact of recent load growth at the state level appears to have benefitted commercial customers more than residential customers

- Some authors have expressed concerns that larger end-use customers may disproportionately benefit from load growth, potentially disadvantaging residential customers¹:
 - ▣ Policymakers generally support the economic development that comes from commercial and industrial (C&I) demand, and large C&I customers tend to be strong advocates, and thus seek lower retail electricity prices
- Based on state-level retail price changes from 2019 to 2024, statistical analysis suggests that a 10% increase in statewide load reduced overall average prices by 0.6 cents/kwh
- Commercial customers benefitted the most from this load growth, with relatively larger price reductions → in part because load growth in states with relatively large price reductions was often led by the commercial customer class
- Residential customers also appear to have benefitted from aggregate load growth from 2019-2024, but to a lesser extent
- On a cents/kWh basis, industrial-customer benefits are on par with residential, though given lower average prices, benefits are much higher on a percentage basis



Notes: Figure presents results from four regressions of a form described later in this slide deck. The dependent variable is the change in the state-average retail price for 'all load', 'residential customers', 'commercial customers', or 'industrial customers', in each case from 2019 to 2024. Multiple independent variables are used, including one defined as the percentage change in total state load from 2019 to 2024.

Knowledge Gaps: Under what conditions does load growth increase vs. decrease prices for different customer classes; how does utility regulation impact these outcomes?

Utility-scale wind and solar deployment does not—alone—appear strongly related to recent retail electricity prices

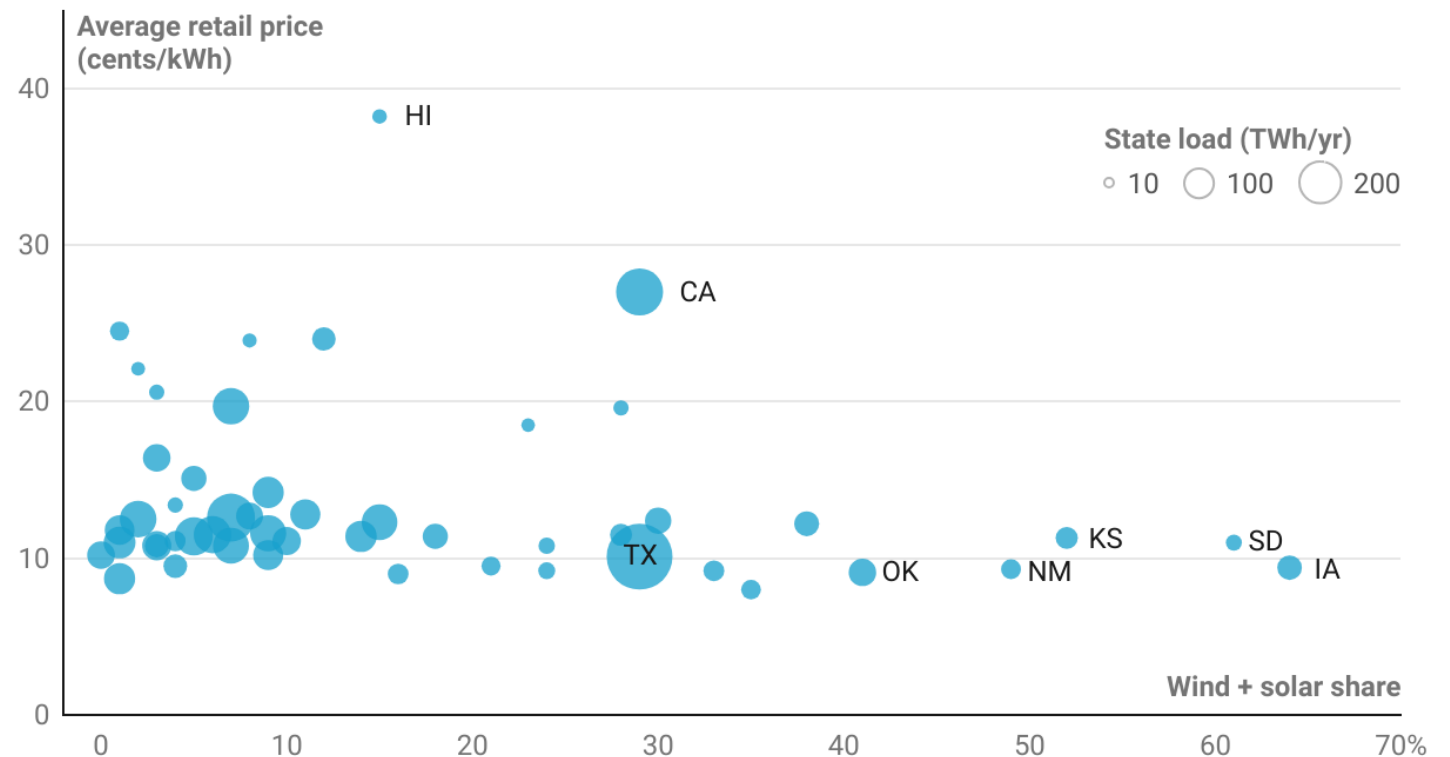
- Some argue that wind and solar increase prices due to both direct project costs and indirect costs associated with transmission buildout and managing variability¹; others contend that, with tax incentives, these sources may increase or decrease prices²
- As shown on right, there is no clear visual relationship between retail prices in 2024 and the in-state share of utility-scale wind and solar as a percent of total generation
- States with the highest utility-scale wind and solar shares often have low prices; states with low- and mid-level wind and solar shares have widely varying prices
- California and Hawaii are outliers in terms of retail prices, but are not the leading states in utility-scale wind and solar shares

¹ e.g., [Lomborg \(2025\)](#)

² e.g., [Wiser et al. \(2024\)](#) and [Pierpont \(2024\)](#)

Average State-Level Electricity Price in 2024 vs. Share of Total in-State Generation from Utility-Scale Wind and Solar

Retail electricity price in cents/kWh in 2024\$. Utility-scale wind+solar share in 2024 only considers in-state generation, ignoring inter-state trade in electricity.



Source: EIA, LBNL • Created with Datawrapper

Note: Graphic shows prices in real 2024\$; relationships are the same in nominal terms

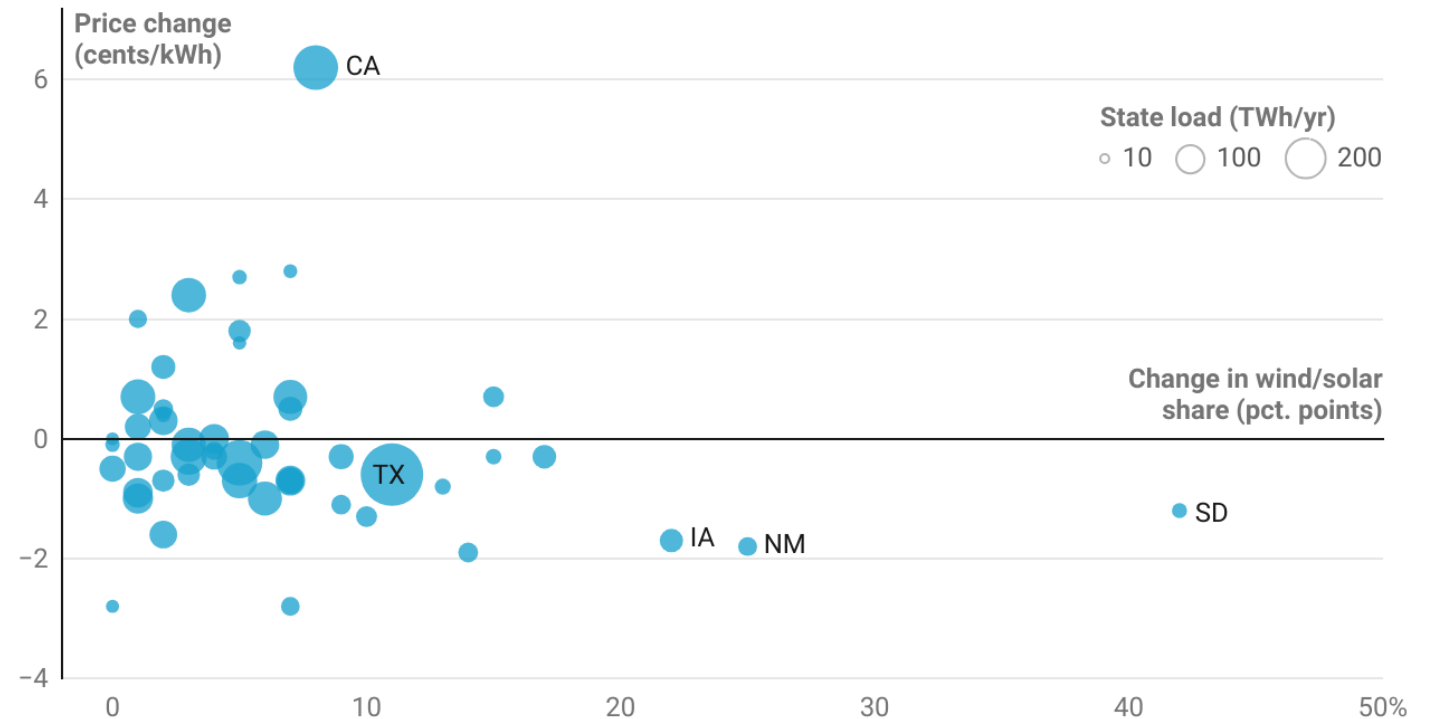
There is some evidence that growth in “market-based” utility-scale wind and solar has reduced retail electricity prices, outside of state RPS’s

- State-level price increases (inflation adjusted) over the last 5 years do not appear driven by growth in state-level utility-scale wind and solar
- California is an outlier in price increases, but has not been a leading state in wind and solar growth over this specific period
- Statistical analysis presented later confirms this finding outside of RPS states and controlling for other variables; instead, there is suggestive (weak) evidence that growth in wind & solar reduced retail prices over the last 5 years
- Many states with RPS policies have seen price increases → see following slide

Knowledge Gaps: Analysis to understand the conditions in which wind and solar have impacted prices, or may do so in the future as penetrations grow (and with or without federal tax incentives)

Growth in Utility-Scale Wind and Solar vs. Retail Price Changes from 2019 to 2024

Price change in cents/kWh, inflation adjusted to 2024\$. Utility-scale wind+solar in-state market share is presented as a percentage point change in share from 2019 to 2024.



Source: EIA, LBNL • Created with Datawrapper

Note: Graphic shows prices in real 2024\$; relationships are the same in nominal terms

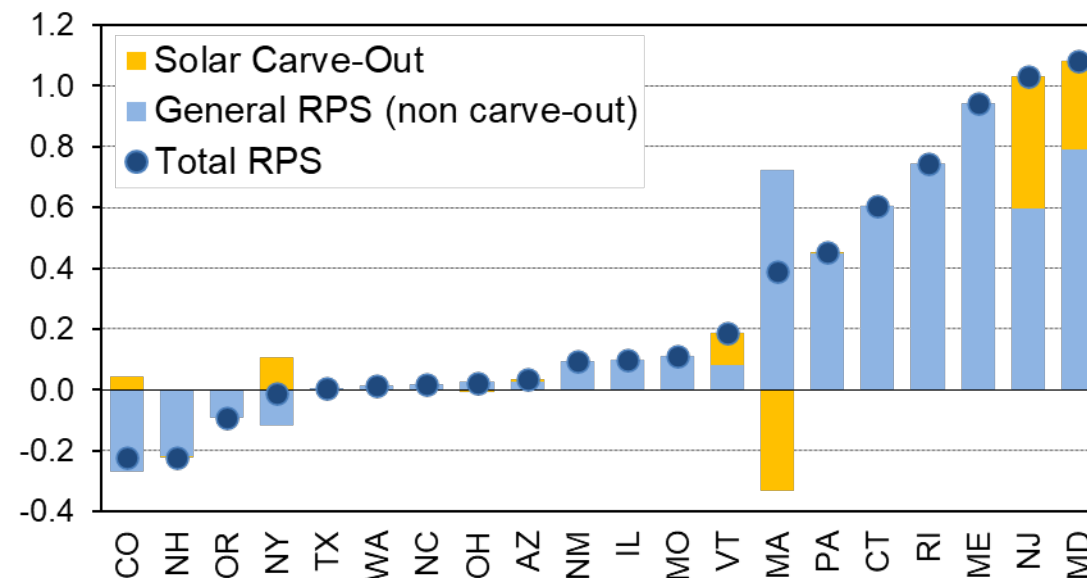
Many state RPS programs have increased retail electricity prices, as expected given the intent of those policies

- 29 states and DC have RPS programs with varying designs; intended to require more renewable energy than the competitive market would otherwise supply with goal of societal benefits, though in practice not all RPS' are binding
- In aggregate, the increase in state RPS requirements from 2019 to 2024 equates to approximately 25% of all utility-scale wind and solar growth in the U.S. over the same period (75% occurred outside state RPS policies)
- RPS compliance cost data vary across states, and may not account for the full suite of cost impacts, such as added integration costs or wholesale electricity price reductions, but can provide a first-order approximation of rate impacts
- For the subset of states with available data, the average increase in RPS compliance costs from 2019 to 2024 equates to a retail price increase of ~0.25 cents/kWh; in the higher cases it is equal to a ~1 cent/kWh rise in retail prices; the largest impacts tend to be in various New England and Mid-Atlantic states¹
- These estimates are broadly consistent with statistical analysis presented later, which controls for other drivers

Knowledge Gaps: Better understanding of how RPS program design (e.g., reliance on unbundled RECs vs. long-term contracts, resource eligibility) and regional resource costs impact retail prices

Change in RPS Compliance Costs from 2019-2024

(cents per kWh of retail sales)¹



¹ For details on RPS compliance cost data and methods, see [Barbose \(2024\)](#)

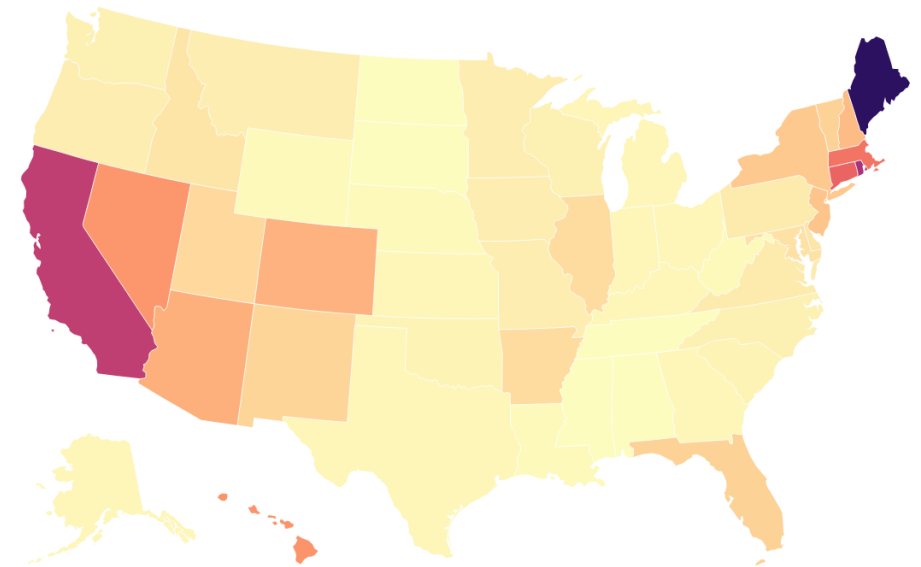
Largely due to ratemaking practices, solar compensated under net energy metering has benefitted adopters while often increasing retail prices

- Net energy metering (NEM) can benefit customers that install solar, yet can increase retail prices, largely because of ratemaking practices:
 - Reduces some utility costs, but other (e.g., fixed) costs must be spread over a smaller sales base under many common rate structures (e.g., net metering with volumetric rates), leading to higher average prices
- Effects are highly variable across states and customer classes, depending on NEM solar levels, retail rate and compensation structures, distribution system impacts, and the presence of other ratepayer-funded programs to support customer-sited solar, among other factors (see next slide)¹
- Statistical analysis considers the net effects of NEM solar growth over the 2019-2024 period; results are imprecise but suggest price impacts of less than 0.5 cents/kWh in 40 states, but as high as ~2 cents/kWh
- Results at the high end are consistent with some estimates for CA², which has seen among the highest levels of NEM solar growth
- Research has found much smaller impacts in the vast majority of states³, most of which have seen much lower rates of NEM solar growth
- **Future impacts may differ** if NEM solar growth is accompanied by, for example, rapid underlying load growth, co-adoption of storage, and advancements in rate design

From 2019 to 2024, growth in NEM solar reduced net electricity sales by over 5% in three states, and by over 2% in another seven states (includes community solar in some states e.g., ME)

Increase in NEM Solar Penetration from 2019-2024

Change in NEM Solar Penetration as a Percentage of Retail Sales



Source: EIA • Created with Datawrapper

¹ [National Academies \(2023\)](#) ² [Sieren-Smith et al. \(2024\)](#) ³ [O'Shaughnessy et al. 2025](#)

NEM solar can impact prices through mechanisms beyond fixed-cost recovery, but these have been less significant in recent years

Beyond its impact on retail sales and fixed-cost recovery, NEM solar can impact retail prices through several other mechanisms, though these have generally been less significant over the recent historical period

Ratepayer-funded incentives, including rebate programs for small-scale solar, or RPS solar carve-outs (especially in states with relatively high solar renewable energy certificate prices)

- Rebate programs have generally declined over time
- The increase in RPS solar carve-out compliance costs from 2019-2024 equates to an average 0.1 cent/kWh increase in retail prices across the 10 applicable states, with a maximum of 0.5 cents/kWh (see earlier slide on RPS costs)

Distribution grid investments and deferrals

- Upgrades may be required on feeders with high grid injections from customer-sited solar, while in other cases customer-sited solar (often accompanied by storage) may defer distribution system investments that would otherwise be required (e.g., on feeders with high load growth)¹
- In either case, impacts are generally modest at the low penetration levels experienced in most states

Side note: Due to ratemaking practices, similar directional effects can occur for energy efficiency (EE), which reduces aggregate utility costs and customer bills but may increase prices if some (e.g., fixed) costs are spread across lower total load.² Statistical analysis suggests that EE has recently had the same impact on prices as other general decreases in load (see key finding #8), whereas NEM solar has distinct, larger impacts (see previous slide). On the other hand, EE that results in load increases (e.g., heat pumps replacing non-electric heating) may reduce retail prices. EE programs also generally reduce participant electricity bills due to reduced consumption.

In addition to impacting load, EE can impact retail prices by virtue of direct programmatic expenditures funded by utility ratepayers. However, EE expenditures declined in most states from 2019-2024, generally placing downward pressure on prices³

Bottom line: Ratepayer-funded EE programs were not significant drivers of retail price increases over the 2019 to 2024 period, likely only modestly impacting prices.

Knowledge Gaps: Better understanding of diverse NEM solar impacts across states and timeframes; and optimal designs of programs that minimize price increases and maximize societal cost reductions and benefits

¹ [Horowitz et al. 2018](#), [Cohen et al. 2016](#) ² [Satchwell et al. 2018](#) ³ [ACEEE 2025](#)

A variety of other state policies, programs & planning decisions can impact prices, but are unlikely to have greatly impacted recent trends in most states

- Programs are sometimes funded via explicit surcharges and in others embedded in other cost categories
- Literature shows that these generally did not play a significant role in recent price changes
- Examples of various policies, programs, and planning decisions include:

Carbon cap-and-trade programs have not been major drivers of recent retail price increases

- California: PG&E prices ~4% higher in 2023 (up from ~2% in 2019); and then offset by rebates to households from auction revenue, reducing effective price impact [[Fowle and Burtraw \(2025\)](#), [CPUC](#), [LAO \(2025\)](#)]
- RGGI: Increased wholesale prices by 3.3-8.3% in 2022; retail price impact <50% than that, and with lower recent change; revenue recycling further reduces impact [[RGGI \(2025\)](#)]

Nuclear decommissioning & cost of new-build can impact prices, but not much recent change outside Vogtle

- Surcharges for decommissioning and spent-fuel for utility-owned plants are modest on a cents/kWh basis, and will not have changed much recently
- The recent addition of Vogtle Units 3 & 4 significantly increased residential prices for Georgia power customers: ~10% increase (~\$15/month) [[Forrester et al. \(2024\)](#)]
- Ratepayers continue to pay for the abandoned V.C. Summer plant in South Carolina, but those costs have not significantly increased recently

Electric vehicle infrastructure build-out is not a significant driver of retail prices or of recent price changes

- California: Year-end 2023 direct impact on residential prices is 0.1% (PG&E), 0.2% (SCE), and 0.9% (SDG&E), roughly doubling in total since 2019 [[CPUC \(2024\)](#)]
- Does not consider price-reducing effects of increases load and other impacts; studies show that, on net, EVs are putting downward pressure on prices [[Shenstone-Harris et al. \(2024\)](#)]

A variety of other state policies, programs & planning decisions can impact prices, but are unlikely to have greatly impacted recent trends in most states

- Additional examples of various policies, programs, and planning decisions include:

Restructuring and retail choice may have impacted past retail prices, but are not likely major drivers of recent trends

- Evidence is mixed on the historical impacts of restructuring and retail choice on retail electricity prices [[Rose et al. \(2023\)](#)]
- Approach to restructuring and retail choice has not changed dramatically in recent years
- Consequently, these factors are unlikely to explain recent price trends

Wholesale market rules impact retail prices but are unlikely to have been a major contributor to changes from 2019 to 2014

- ERCOT's market design can create significant shorter-term increases in wholesale (and retail) prices, but Texas' retail prices remain relatively low overall [[EIA \(2021\)](#)]
- PJM's 2025-2026 capacity auction resulted in higher prices, impacts retail prices in 2025-26 (but not 2024)
- West "EIM" estimated to have reduced wholesale prices [[WEIM \(2025\)](#)]
- Evidence that self-scheduling has allowed some higher-cost, utility-owned thermal plants to remain online and operating, increasing retail prices

Low-income direct bill assistance generally does not impact overall average retail prices as it reflects a cost shift

- California has among the largest programs (CARE): ~2-4% higher retail prices for non-CARE customers to subsidize discounts, increasing over time [[LAO \(2025\)](#), [CPUC \(2025\)](#)]
- Some other states have similar programs, but typically less generous and so with impacts at or below 2-4% for non-benefitting ratepayers
- Represents a cost shift, so no change in absolute average retail prices across all customers

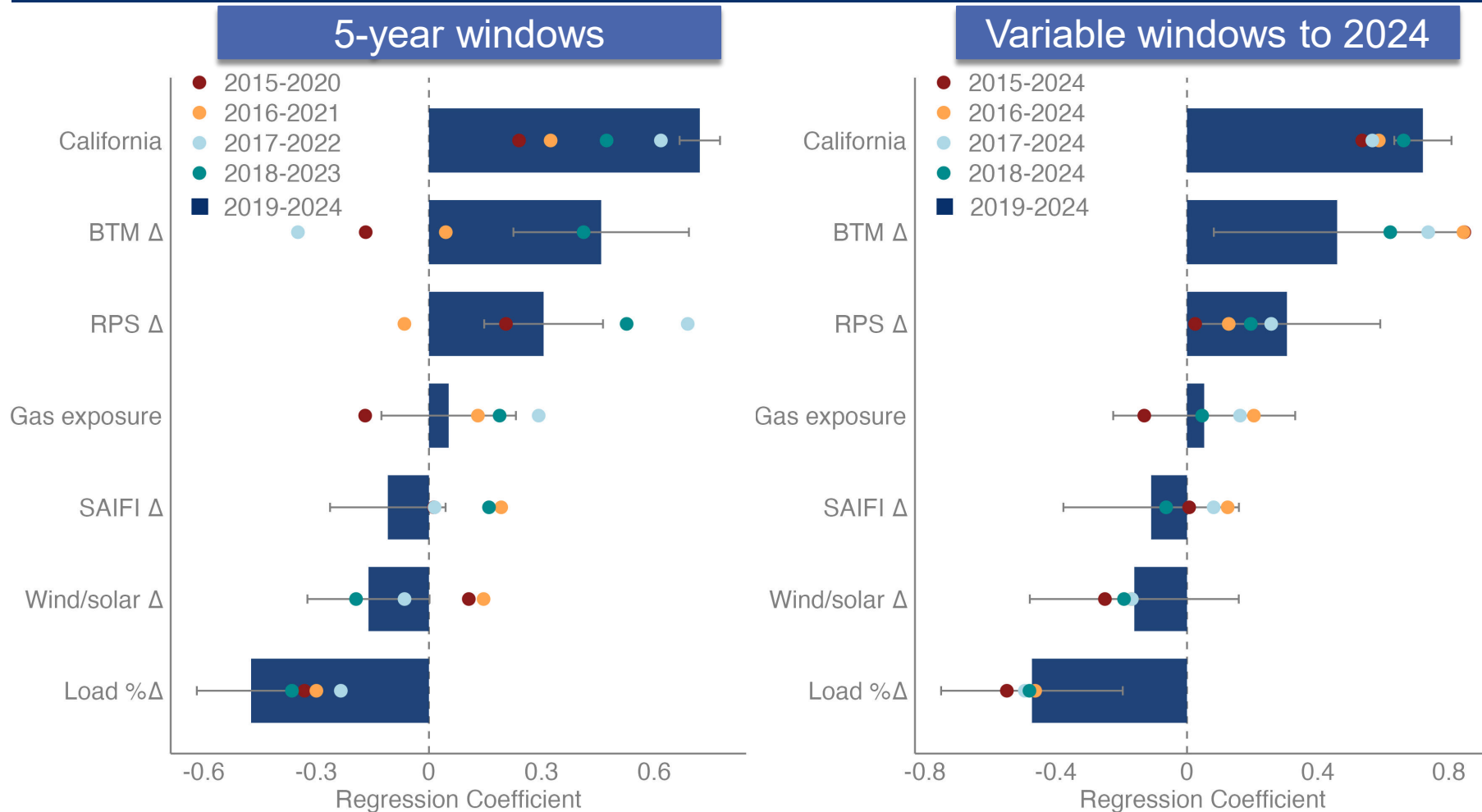
Statistical analysis

Regression analysis was one—but not the only—component of our work

- LBNL developed a statistical model to estimate causal effects of various factors on inflation-adjusted retail price changes over recent periods: ***addresses subset of factors described on previous slides***
- **Dependent variable:** change in average state-level price over a specified period
- **Independent variables:** (a) load change, (b) BTM growth, (c) utility-scale wind & solar growth, (d) RPS requirement, (e) natural gas exposure, (f) change in SAIFI, (g) CA dummy, (h) lagged price change *[included many additional variables in supplemental regressions]*
- **Issues with the model:**
 - **Low statistical power:** 48 observations in each regression!
 - **Geography:** some variables may be better specified at utility or regional level
 - **Blunt proxies:** NEM-BTM growth but not variations in compensation
 - **Poor proxies:** storms and wildfires hard to capture, as well as distribution costs generally
 - **Cost recovery:** diversity in how costs are recovered in rates
 - **Correlations:** BTM solar and RPS
 - **Endogeneity:** BTM solar, perhaps less-so customer load
- **But despite it all, the model performs reasonably well – or at least better than expected**
 - High R2 (0.86 for 2019-24); predictions within 0.5 ¢/kwh of the actual change in 38 of the 48 states

$$\Delta p_{Y-y} = \alpha + X\beta + \Delta p_{y-\underline{y}}\gamma + \varepsilon$$

Regression results support many of the core price drivers: this slide shows standardized regression coefficients over varying timeframes



Notes: Dependent variable is change in state average retail price in real (2024) dollars; RPS Δ = change in required RE generation from RPS x renewable energy certificate price cohort; BTM Δ = change in NEM behind-the-meter solar normalized by sales; Gas exposure = % of state generation from gas x average state gas prices; SAIFI Δ = change in frequency of grid service interruptions; wind/solar Δ = change in wind/solar as share of state generation; load %Δ = percentage change in load. All variables are standardized. The CA dummy is rescaled by its standard deviation.

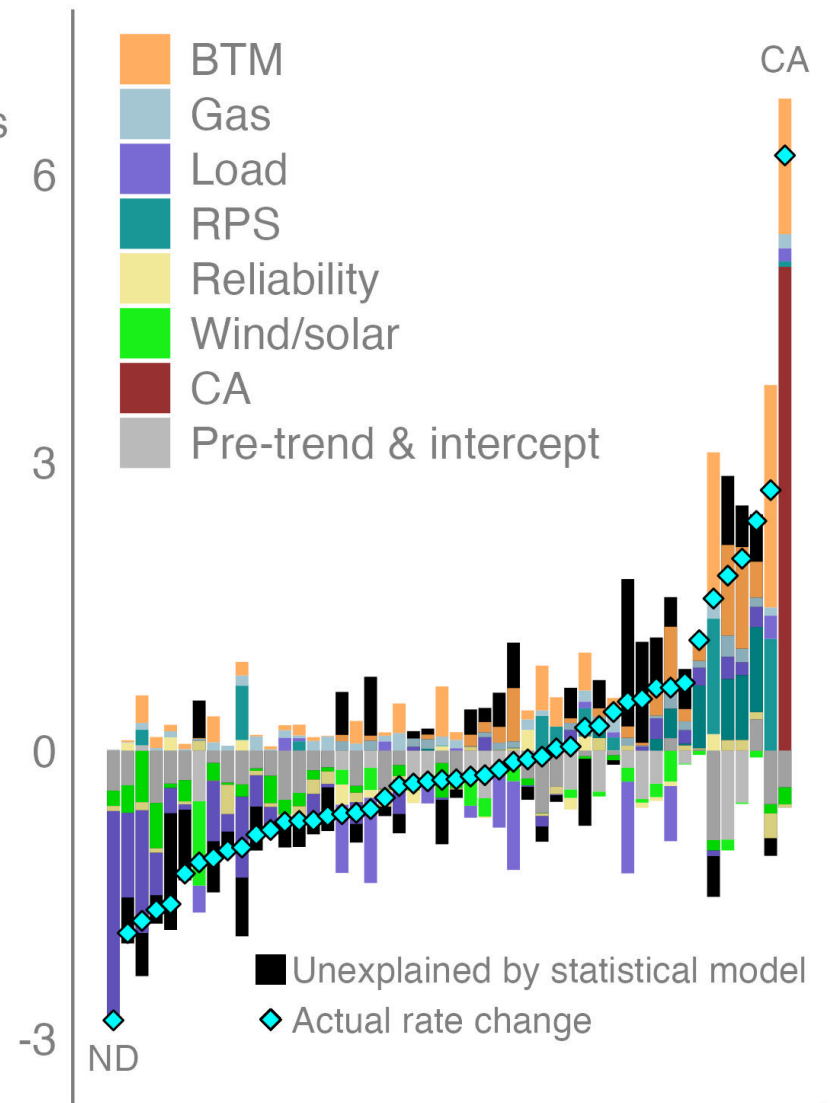
Other variables tested in supplemental regressions typically have statistically insignificant effects that are often inconsistent across timeframes: ISO market, retail choice, utility ownership, EV penetration, EE savings (beyond impact on load), demand response, AMI—effects may be too small or idiosyncratic for identification with these methods; there is some suggestive (weak) evidence that coal retirements tended to reduce retail prices

Regression results for a subset of possible price drivers: 2019-2024

(does not well-estimate storm and wildfire impacts, and distribution costs more generally)

- Figure illustrates predicted state-level price changes (2019-2024) from model, and compares those to actual changes
- Model does not accurately estimate relative impacts in individual states (its best thought of as estimating average impacts across states), in part as illustrated by the “unexplained” component of bar chart
- Nonetheless, model predicts recent price changes quite well: high R2 (0.86 for 2019-24), predictions are within 0.5 c/kwh of the actual change in 38 of the 48 states
- Figure shows how **increases in load** help explain recent price changes in states with declining prices (75% of utility-scale wind & solar growth outside of RPS helped)
- **NEM (BTM) solar** and **state RPS** often help explain price changes in states with increasing prices (**gas-price exposure** also impacts results, mostly in earlier periods)
- **California** is an outlier, with inflation-adjusted price changes far exceeding those in other states: impacted in large part by wildfire-related costs
- Model does not well capture distribution expenditure and, related, wildfire and storm impacts—previously found to also be primary drivers of recent price changes

Predicted and Actual Price Changes (¢/kWh)



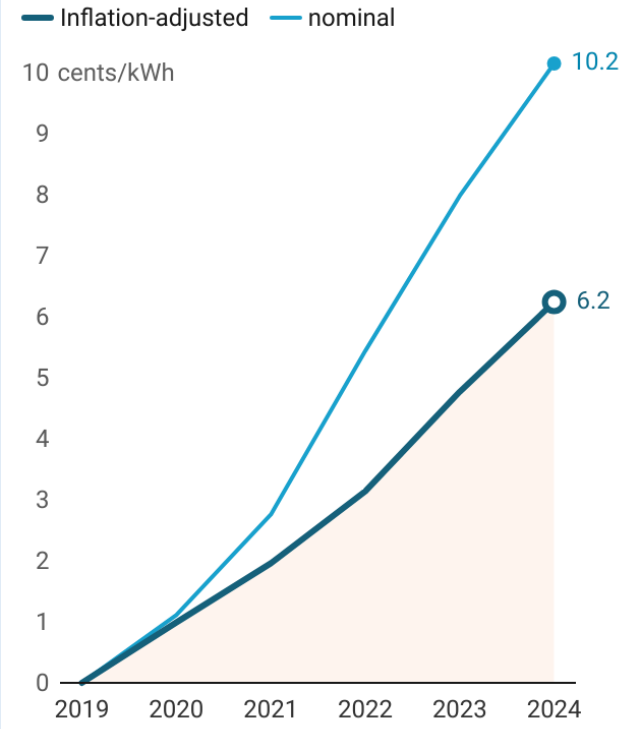
Six case studies

California Case Study

Largest state-level increase in inflation-adjusted average retail prices from 2019-2024

Case focuses on impacts averaged across 3 IOUs: PG&E, SCE, SDG&E, which provide bundled or delivery services to ~70% of statewide load

California: change in average retail price since 2019



Source: EIA • Created with Datawrapper

Primary Price Drivers in California

Factors impacting 3 large IOUs' average retail electricity prices from 2019 to 2024

Primary Factors Increasing Prices from 2019 to 2024

Wildfire mitigation and liability costs¹
~4.3 ¢/kWh

Inflation in distribution (& transmission) costs²
~3.7 ¢/kWh

Net metering for customer-sited solar³
~2.5 ¢/kWh

Secondary Factors Impacting Price Changes

Public purpose programs (EE, low-income, etc.)⁴
~0.2 ¢/kWh

Renewables Portfolio Standard⁵
<0.5 ¢/kWh

Notes: Estimates are in nominal dollars, not adjusted for inflation. For a variety of reasons, they cannot be precisely compared to the EIA-reported statewide average price changes shown on the left, not least of which because the case study focuses on the three large IOUs, while the chart on the left depicts statewide increases. California has aggressive climate and clean energy policies, in part reflected in the net metering, public purpose charge, and RPS impacts. Other impacts exist but likely influence overall average prices more than price changes over this specific 2019-2024 timeframe.

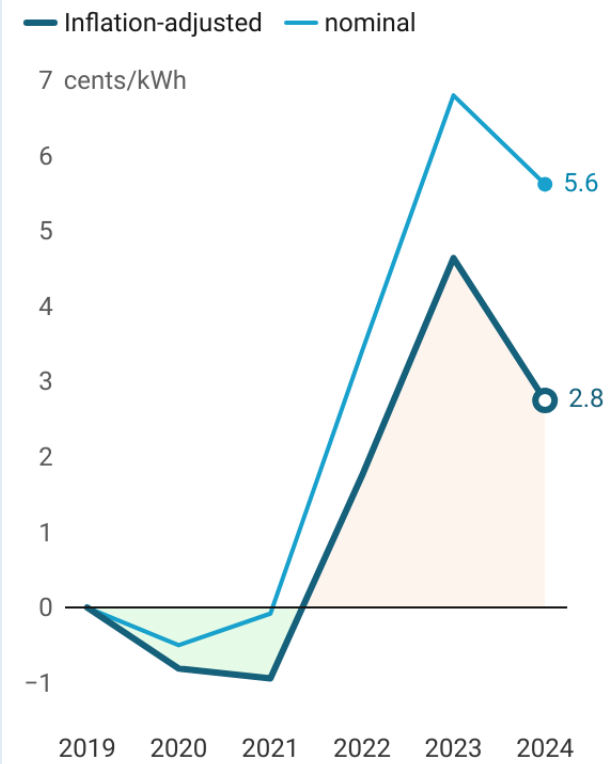
Sources: ¹ CPUC: [2024](#), [2023](#); from 2019-2023, 40% of these costs were for wildfire insurance and catastrophic events, with 60% for actual mitigation; ² CPUC: [2024](#), [2023](#), [2024](#); transmission is in parentheses as it represents just ~15% of the increase over this period, with the rest being non-wildfire related distribution costs (note that the effect of overall inflation will largely show up here); ³ [CPUC 2024](#), [2024](#); shown here are average impacts across all customer classes, but in reality there would be a larger impact for residential and smaller impact for C&I; the solar industry disputes these figures, with a [2024 study](#) suggesting a ~0.5 ¢/kWh price reduction from 2019-2024; an analysis by [Borenstein](#) that focused solely on residential solar (not C&I) can be used to estimate an overall average all-sector price increase of ~1.6 ¢/kWh from 2019-2024; CPUC [2024](#) provides an end-of-2024 assessment, which can be used to calculate a 2019 to end-of-2024 all-sector impact of 3.5 ¢/kWh; ⁴ [CPUC 2024](#); ⁵ Extrapolated in part from CPUC [2025](#), [2020](#), [2024](#), [PG&E 2023](#), and focused on direct compliance costs for bundled and delivery (i.e., CCAs, ESPs) customers of three IOUs, does not consider any broader impacts.

Maine Case Study

Third-largest increase in inflation-adjusted average retail prices from 2019-2024, after California & Hawaii

Case focuses on Central Maine Power, which provides distribution services to ~78% of statewide load

Maine: change in average retail price since 2019



Source: EIA • Created with Datawrapper

Primary Price Drivers in Maine

Factors impacting CMP's average retail electricity prices from 2019 to 2024

Factors Increasing Prices from 2019 to 2024

<p>Winter storm recovery costs¹</p> <p>~1.6 ¢/kWh</p>	<p>Net billing for distributed energy²</p> <p>~1-1.5 ¢/kWh</p>	<p>Renewables Portfolio Standard³</p> <p>~1 ¢/kWh</p>	<p>Distribution investments & operations⁴</p> <p>~1 ¢/kWh</p>
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Factors Driving Price Variability

<p>Natural gas prices⁵</p> <p>~5 ¢/kWh: increased prices through 2023, then declined to ~2019 levels</p>	<p>Transmission costs⁶</p> <p>~1 ¢/kWh: increased prices through 2022, then declined to ~2019 levels</p>
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Notes: Estimates are in nominal dollars, not adjusted for inflation. For a variety of reasons, they cannot be precisely compared to the EIA-reported statewide average price changes shown on the left. The natural gas impacts are hard to establish with precision but impacts from the Ukraine-Russia war were most acute in 2023 (driven by commodity costs and regional pipeline constraints), with prices in 2024 falling closer to historical levels.

Sources: ¹ [MPUC filings \(multiple years\)](#); ² [MPUC filings](#); [SEA analysis](#); higher value based on narrow definition of ratepayer benefits, lower value a more expansive assessment; ³ Extrapolated in part from [MPUC filing & Barbose \(2024\)](#) and focused only on direct compliance costs; overall impact for Maine ratepayers reported, not uniquely CMP, and does not consider any broader impacts; ⁴ CMP rate-cases in [2018](#) & [2022](#) that established base distribution revenue requirements; ⁵ [MPUC](#); the Ukraine-Russia war (combined with regional pipeline constraints) placed significant upward pressure on electricity supply prices in New England in 2022-2023, including Maine; those impacts have since moderated as natural gas prices declined; ⁶ [CMP filing](#)

North Dakota Case Study

Largest decrease in average retail prices from 2019-2024

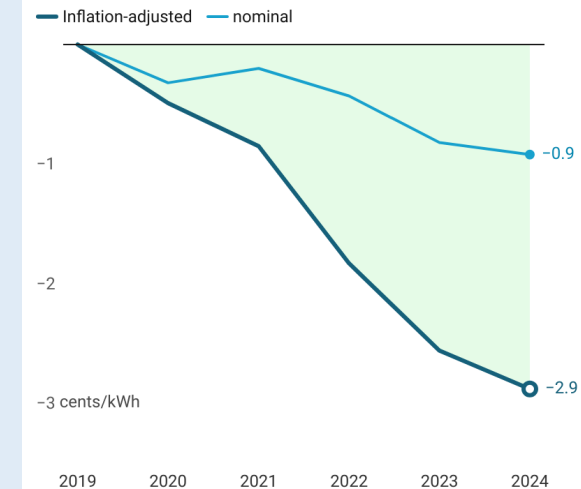
C&I prices declined significantly in nominal & inflation-adjusted terms; residential prices flat in nominal & declined in real \$.

Primary drivers:

- Substantial growth in C&I load
 - Lower cost to serve = lower avg. prices
 - Spreading fixed costs = lower C&I prices
- Abundance: supply > demand
- Declining cost of supply (in real \$)

Note: A number of ND utilities have proposed price increases in 2025

North Dakota: change in average retail price since 2019

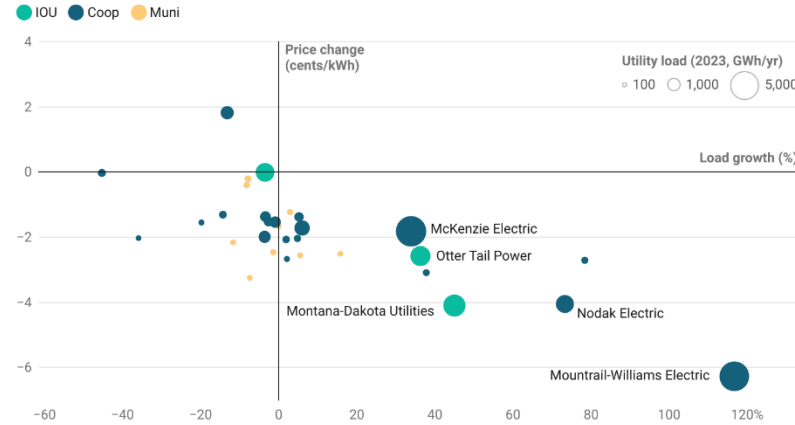


Source: EIA • Created with Datawrapper

1 The utilities that saw the most load growth from 2019-2023 generally experienced the largest overall-average reduction in prices

North Dakota: Impact of Load Growth on Utility-Level Average Retail Price Changes from 2019-2023

Price change in cents/kWh, inflation adjusted to 2024\$. Load growth in percentage terms from 2019 to 2023.



Load growth contributors were: Baaken oil and gas (Mountrail-Williams, McKenzie, Montana-Dakota), cryptocurrency/data centers (Nodak), and agricultural processing (Otter Tail); larger utilities that did not experience as much load growth generally did not decrease inflation-adjusted prices as much; Xcel-NSP noted that load contraction required nominal price increases

2 Load growth came from C&I, and C&I benefited from price declines; residential customers were not harmed as prices declined in real dollar terms

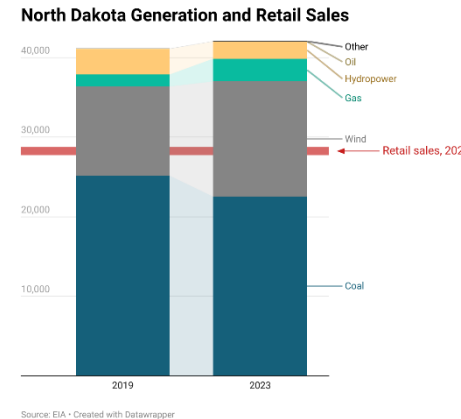
North Dakota: Impact of Utility- and Sector- Specific Load Growth on Retail Price Change from 2019-2023

Price change in cents/kWh, inflation adjusted to 2024\$.

Utility	Residential Load Growth	Residential Price Change	C&I Load Growth	C&I Price Change
Mountrail-Williams Electric	4%	-1.4	126%	-6.7
Montana-Dakota Utilities	0%	-1.6	72%	-4.7
Nodak Electric	-5%	-1.9	116%	-3.6
Otter Tail Power	-4%	-1.0	58%	-2.8
McKenzie Electric	-4%	-1.1	35%	-1.8
All Other Utilities	-0%	-1.1	-5%	-0.5
Statewide: All Utilities	-1%	-1.3	41%	-2.7

3 Importantly, load growth was matched with abundant electricity supply over this period

- State had sizable coal generation, significant and growing low-priced wind power, and growing low-priced natural gas
- In aggregate, in-state supply well exceeded in-state demand; not a supply constrained scenario over this period, at least as relates to generation



Source: EIA • Created with Datawrapper

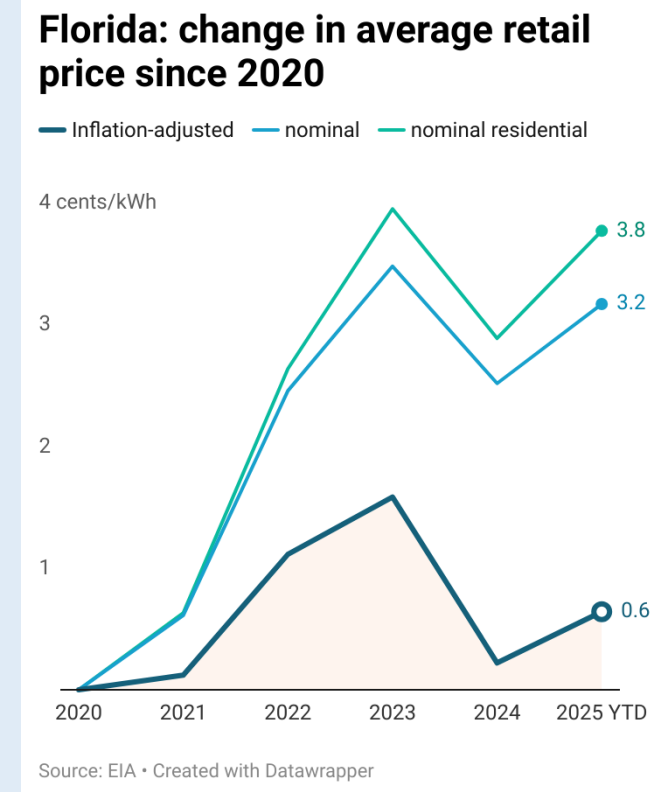
4 Generation (& trans.) costs were flat in nominal dollars, declined in inflation-adjusted terms

- It was not just load growth:** Many utilities without growth also saw inflation-adjusted prices decline over this period
- Basin serves multiple coops: since 2019, inflation-adjusted G&T costs charged to members declined by ~1.5 ¢/kWh
- Minnkota also serves public power in state: since 2019, inflation-adjusted G&T costs declined by ~1.5 ¢/kWh
- Fuel & purchased power for Otter Tail (-1 ¢/kWh), MDU (-0.5 ¢/kWh), Xcel-NSP (no change) were flat or declined in real \$
- Reason:** low-cost fuel & purchased power plus economic dispatch & retirement of some higher-cost coal, replaced w/ lower-cost wind & gas (Montana-Dakota, Otter Tail, Otter Tail)

Florida Case Study

Focus on residential prices from 2020 to mid-2025 (given data availability) for average of 3 large IOUs: FPL, Duke, Tampa (78% of state retail sales)

Residential prices were up 3.8 ¢/kWh in nominal dollars statewide (greater than all-sector average of 3.2 ¢/kWh); adjusting for inflation, residential prices increased by ~0.9 ¢/kWh (vs. all-sector average of 0.6 ¢/kWh)



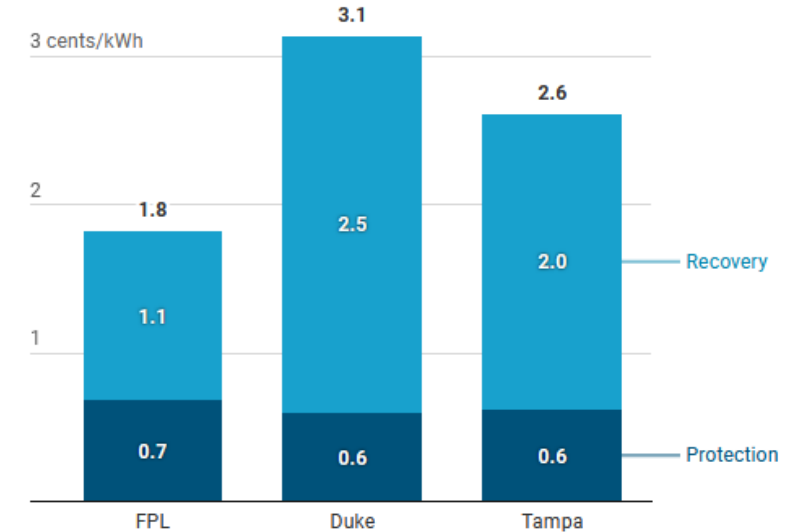
General sources: PSC filings; utility tariffs

1 Storm cost recovery & protection were the primary drivers of residential price increases from Jan. 2020 to Sept. 2025: average among 3 IOUs: +2.2 ¢/kWh

- Florida is especially vulnerable to hurricanes
- Guided by legislation and regulation, IOUs have significantly increased expenditures since 2020 to harden systems, protect against future storms
- Additionally, hurricanes Debby, Helene & Milton hit in 2024, resulting in significant *temporary* recovery costs that were passed to customers beginning in 2025 for a duration of 1-year (FPL, Duke) to 1.5-years (Tampa)

Increase in storm protection and recovery costs from January 2020 to September 2025

Nominal \$, not adjusted for inflation



Source: Florida PSC, FPL, Duke, Tampa • Created with Datawrapper

2 Fuel costs played a significant role in price variability and some role in price increases

- ~75% of the state's generation comes from natural gas
- Gas price increases caused residential prices to spike by ~2 ¢/kWh from 2020 to 2023, with a subsequent decline
- Gas prices remained higher in 2025 than 2020, resulting in a ~0.5 ¢/kWh electricity price increase in nominal terms (impact negligible or slight decrease if inflation adjusted)

3 Other distribution, transmission, & (non-fuel) generation costs impacted prices

- Increased avg. prices by ~1.4 ¢/kWh in nominal \$, but reduced prices by ~0.2 ¢/kWh after adjusting for inflation

4 Other factors played secondary roles

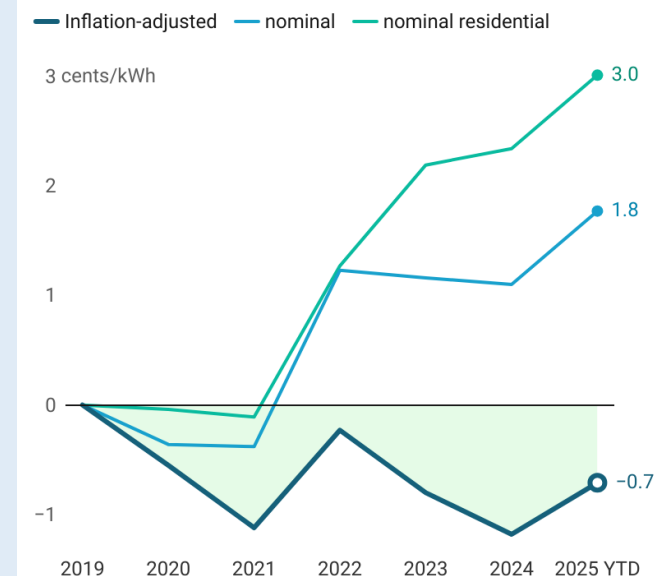
- Conservation and environmental compliance costs were, cumulatively, up on average by 0.1 ¢/kWh
- Net metering with BTM solar might have increased prices by ~0.15 ¢/kWh
- Utility-owned solar buildout increased statewide solar share to 7% in 2024, up from 2.6% in 2020
 - Utilities must demonstrate cost savings on present-value basis, resulting in expected retail price reductions over time
 - FPL estimates \$1.1 billion in fuel cost savings cumulatively from 2017-2024; utilities describe cost effectiveness and ability to mitigate price shocks from gas price changes
 - But can result in small retail price increases in near term in some cases given upfront CapEx

Virginia Case Study

Focus on residential prices from 2019 to mid-2025 for Dominion Energy (~65% of state retail sales)

Residential prices were up ~3 ¢/kWh in nominal dollars statewide (greater than all-sector average of 1.8 ¢/kWh); adjusting for inflation, residential prices decreased by ~0.15 ¢/kWh (vs. all-sector average decrease of 0.7 ¢/kWh)

Virginia: change in average retail price since 2019



Source: EIA • Created with Datawrapper

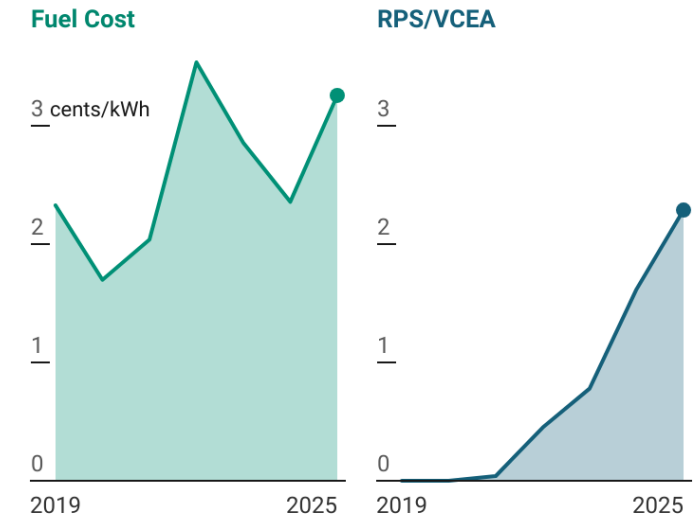
General sources: SCC filings; utility IRP & tariffs

1 State RPS/VCEA and Fuel Costs were the primary drivers of residential price changes from 2019 to mid-2025:

- RPS/Virginia Clean Energy Act (VCEA) impact (~2 ¢/kWh) on prices is considerably higher than RPS' in other states, in part due to utility-owned projects and related cost recovery before projects come online (such that ratepayers are paying in advance for future supply); ~60% of impact partly explained by this nuance
- Virginia depends on natural gas (59% of total generation); fuel cost riders were **0.9 ¢/kWh** higher in mid-2025 than in 2019; the consequences of the Ukraine-Russia war will be felt for years to come as some natural gas costs from ~2022 were securitized and will impact prices for 7 years

Dominion: impact of fuel costs and RPS on residential retail prices

nominal cents/kWh (not inflation adjusted)



Source: Dominion • Created with Datawrapper

2 Load Growth Mitigated Price Increases

- Statewide load grew 15% from 2019 to 2024
- Helped keep many other costs, in cents/kWh, flat on a nominal basis and declining in inflation-adjusted terms as fixed costs were spread over more load
- Result: after adjusting for inflation, residential prices are about the same in 2025 YTD as in 2019

3 Other factor played secondary roles

- **~0.45 ¢/kWh** due to undergrounding & grid transformation
- **~0.35 ¢/kWh** price increase due to nuclear relicensing

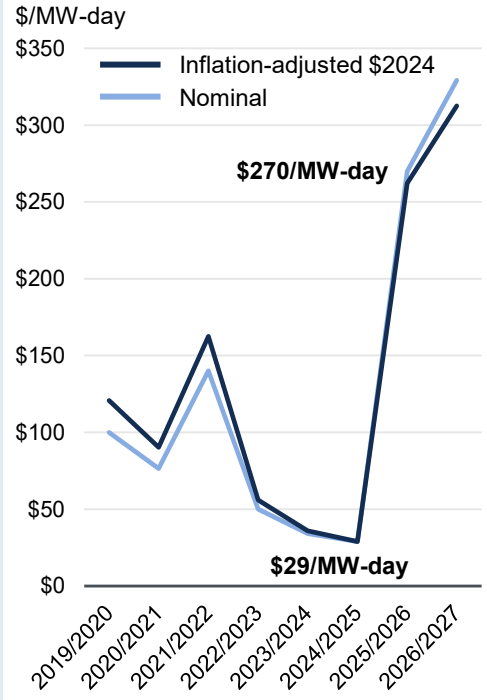
4 More price increases on the horizon

- Dominion's 2025 rate case proposes an increase in base rates for the first time in many years, reflecting increases in the cost of labor, materials and equipment, and the cost of reliably serving growing customer load (predicts 5.5%/year)
- Requested base rate increase of \$8.5/month in 2026 and another \$2/month in 2027, suggests changing relationship between load and prices
- Separately, is also asking for a \$10.9/month increase to cover increased capacity costs and higher past and expected natural gas fuel costs

PJM Capacity Auction Case Study

This case study focuses on the impact of the recent PJM capacity auction broadly, rather than on an individual state. Recent spikes in clearing prices demonstrate that load growth need not always decrease retail prices in the near-term but can instead increase retail prices in a tight supply market.

PJM: Capacity Auction Clearing Price History



Data from PJM compiled by [NRG](#) with inflation data from the [Bureau of Labor Statistics \(BLS\)](#)

PJM's capacity auction clearing price increased dramatically between the 2024/2025 delivery year and the 2025/2026 delivery year due to a confluence of factors...

- 1

Data Center Load Growth

↑

174% increase in auction revenues

The summer peak load forecast used in the auction included almost 8 GW of data center load. In the near term, data centers make up of over 90% of large load additions in PJM. The Independent Market Monitor (IMM) calculates that, all-else constant, the embedded and incremental data center load accounted for a 174% increase in auction revenues.
- 2

Summer Capacity Ratings for CC/CT Resources

↑

23 - 118% increase in auction revenues

The IMM estimates that limiting CC and CT resources to their summer capacity ratings rather than their higher winter ratings increased auction revenues between 23% and 118%, depending on what impact is assumed on the installed reserve margin.
- 3

Demand Curve Price Cap

↑

68% increase in auction revenues

The maximum point on the Variable Resource Requirement curve (demand curve) used in the auction was raised to Gross Cost of Net Entry (CONE) instead of 1.5× Net CONE, due to previous concerns that the Net CONE would be too low.
- 4

Adoption of Effective Load Carrying Capability (ELCC) Accreditation Method

↑

49% increase in auction revenues

This was the first auction held under the new rules to calculate different resources' capacity value based on their ability to contribute to reliability during high-risk hours. The ELCC ratings of most resources decreased under this approach.

Other major drivers that contributed to the high clearing price included the exclusion of Reliability Must Run units from the auction supply curve and the withholding of exempt capacity. Although all of these factors put upwards pressure on clearing prices, the resulting auction outcomes signal a real need for new resources to meet the growing demand of the region, similar to how high clearing prices spurred development of new generation in certain areas of PJM (EMAAC, MAAC) in the past. One can therefore also interpret the rapid increase in clearing prices as indicative of prices that were too low in previous auctions.

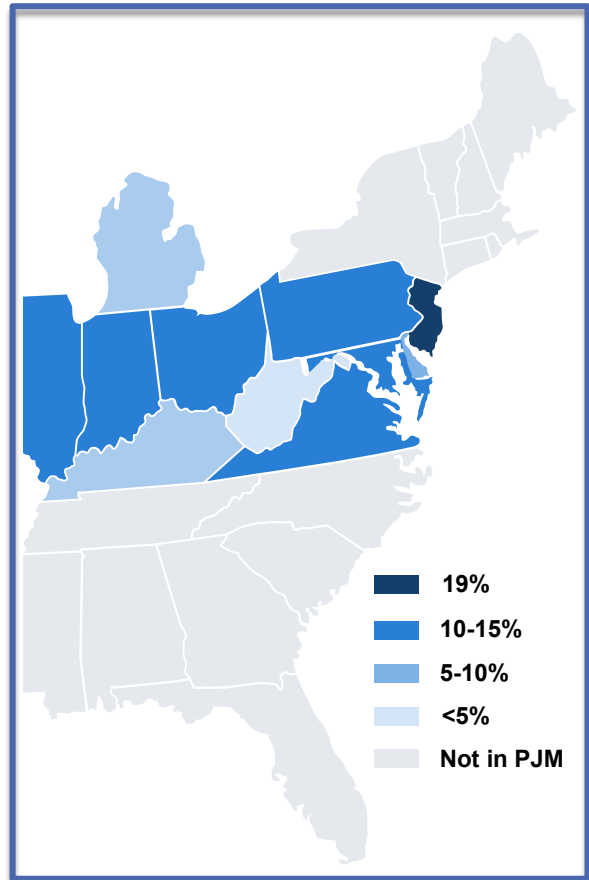
Because of the lag between when the capacity auction takes place and the time of delivery, the impact of the high capacity-prices from the 2025/2026 auction (results available in June 2024) were not felt in retail electricity prices until mid-year 2025.

Notes and source: Reliability Must Run units are power generation units that are required to remain in service or continue operating to maintain grid reliability, even if they are not economically competitive in energy markets. Data from Monitoring Analytics' [IMM Analysis of the 2025/2026 RPM Base Residual Auction Parts A through G](#)

PJM Capacity Auction: Case Study

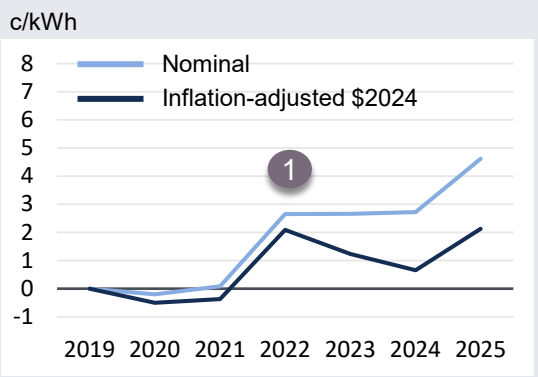
Retail Electricity Price Impacts

Average Increase in Retail Prices Between July 2024 & July 2025



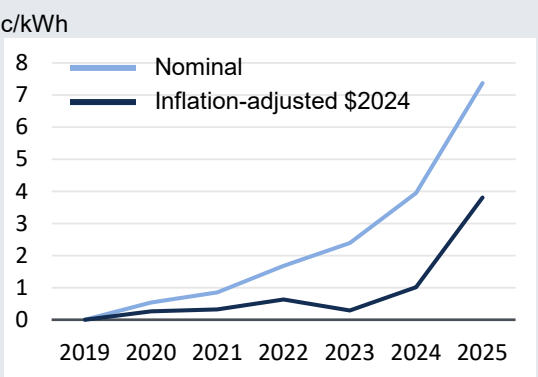
Notes and source: States with vertically integrated utilities are shielded to some extent from capacity auction price spikes because utilities can self-supply instead of purchasing capacity from PJM: from [EIA Electricity Monthly Update](#) July 2025

Pennsylvania Change in mid-year average retail price since 2019



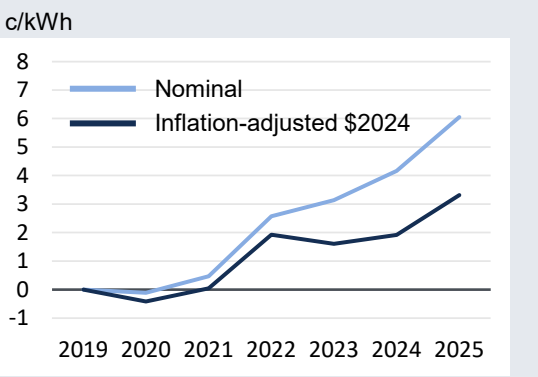
- Following the 2024 capacity auction, Governor Shapiro filed a [complaint](#) against PJM, citing “double-digit” bill increases for Pennsylvania ratepayers as a result of the auction.
- PJM agreed to set a lower price cap for the subsequent capacity auction as a result of Shapiro’s complaint, reducing it from over \$500/MW-day to \$329/MW-day.
- PPL increased their [price-to-compare](#) in June 2025 by almost 16% relative to prices for the previous six months for residential and C&I customers. Other utilities saw similar increases.

New Jersey Change in mid-year average retail price since 2019



- New Jersey is experiencing some of the highest price increases of all PJM states in summer of 2025.
- In its [announcement](#) of the 2025 Basic Generation Service auction results, the NJ Board of Public Utilities reported that residential ratepayers are expected to face monthly increases of over \$20 compared to previous bills, with percentage increases ranging from 17.2% to 20.2%, depending on the utility.

Maryland Change in mid-year average retail price since 2019



- In a [report](#) released in August of 2024, the Office of People’s Counsel (OPC) in Maryland estimated that the average increase on residential customers’ monthly bills would be between \$4-18 due to the capacity auction alone.
- The MD OPC [filed a FERC complaint](#) against PJM asking to reduce the costs of the capacity auction by \$5 billion, citing the exclusion of two Reliability-Must-Run resources in the Baltimore-area as a contributor to the high clearing price.

1 States also experienced a large increase in retail prices in 2022 resulting from the surge in natural gas prices, a consequence of the Ukraine-Russia war. The impact of these gas price spikes varied by state, depending on how exposed a state was to gas prices and how the cost increase was passed to retail customers.

Summary of drivers of recent changes in and variations among state-level retail prices

Summary of primary drivers of state-level price changes: 2019-2024









Key take away: Many states did not experience outsized price changes in real dollar terms. For those states that did experience such price changes, the drivers were varied and diverse. Based on our analysis and available literature, the largest drivers, at least for subsets of states, are summarized to the right.

Important note: Though many of the past drivers may have similar effects in the future, that need not be true in all cases. National load growth was modest over the time-period of focus for this slide deck but is now accelerating, which may change future price drivers. Tax credits for wind and solar were also available, which have been altered via legislation.

This analysis does not seek to predict future retail electricity prices and related drivers, and nor does it prognosticate on approaches to reduce retail electricity prices.

Key Drivers of State-Level Retail Electricity Price Changes from 2019 to 2024

(beyond economy-wide inflation)

Price Driver	Maximum Size	Geographic Breadth	Discussion
Replacement & hardening of aging distribution (and transmission)	 medium	Large	Under 1 ¢/kWh in majority of states after adjusting for inflation, but reasonably widespread impact given scale of distribution investments and supply-chain constraints.
Extreme weather & wildfires: recovery and mitigation	 larger	Medium	As much as 4 ¢/kWh in California, but impacts of 0.5-1.5 ¢/kWh in a number of states in the West, and on the East and Gulf coasts.
Natural gas price variability	  larger	Large	As much as over 2 ¢/kWh increase through 2022-2023, with subsequent decrease; most acute impacts in Northeast, NV, FL, PA, etc.
Customer load growth	 medium	Medium	Over 1 ¢/kWh in only a couple especially high-growth states, with a handful of others over 0.5 ¢/kWh; relationship may change in future.
Utility-scale wind & solar (market-based)	 medium	Medium	75% of wind and solar growth occurred outside RPS; may have reduced retail prices by over 0.5 ¢/kWh in a couple states, under 0.5 ¢/kWh in many others.
State Renewables Portfolio Standard policies	 medium	Medium	As much as ~1 ¢/kWh in a few Mid-Atlantic and New England states; lower and varied impacts in many other states with RPS programs.
Net energy metered solar	 larger	Small	As much as ~2 ¢/kWh in California and over 1 ¢/kWh in small number of other high-growth states especially in the Northeast; low impacts in most states.

Notes: Illustration seeks to show general tendencies. A 'larger' maximum size is defined as an impact of 2 ¢/kWh or more in at least one state; a 'medium' maximum size is defined as a meaningful but smaller impact of under 2 ¢/kWh--see the notes column for additional details. A 'large' geographic breadth implies that the price impact may be meaningful among roughly one-third or more of U.S. states, whereas 'small' signifies meaningful impacts in perhaps a handful or fewer states--again, see the notes column for additional details.

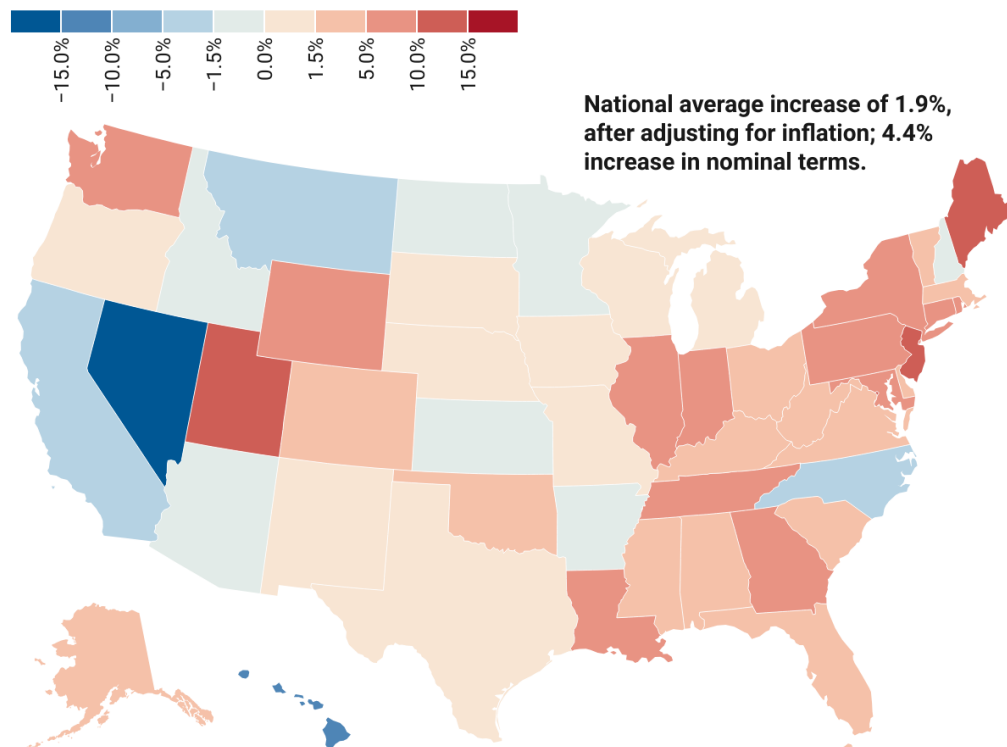
Brief highlights of 2025 developments

Retail prices are outpacing inflation nationally: 4.4% increase in average from Jan-July 2025 relative to 2024, 1.9% when adjusted for inflation

Review of filings, articles and tariffs suggests varied drivers for price increases in the last year: most prominently, increased natural gas, wholesale power, and capacity prices; inflation and hardening of distribution assets; and increased transmission and storm recovery costs.

Percentage Change in State Retail Electricity Prices: Average January-July 2025 vs. January-July 2024

Percentage change, adjusted for inflation in 2024\$



Source: EIA • Created with Datawrapper

Primary Drivers of Price Changes from 2024 to 2025

Stated reasons for price changes from July 2024 YTD to July 2025 YTD, for those states with average increases or decreases of >1.5%, after adjusting for inflation.

	INCREASES >1.5%, 30 states	DECREASES > 1.5%, 5 states
Fuel / wholesale power	19	5
Distribution: inflation & hardening	16	0
Capacity prices	8	0
Transmission costs	8	0
Storm cost recovery	8	0
Generation CapEx	4	0
Wildfire mitigation	3	1
Clean energy policy	3	0
Nuclear energy	2	0
Public benefits (EE/LI/etc)	2	0
Net energy metering	1	0

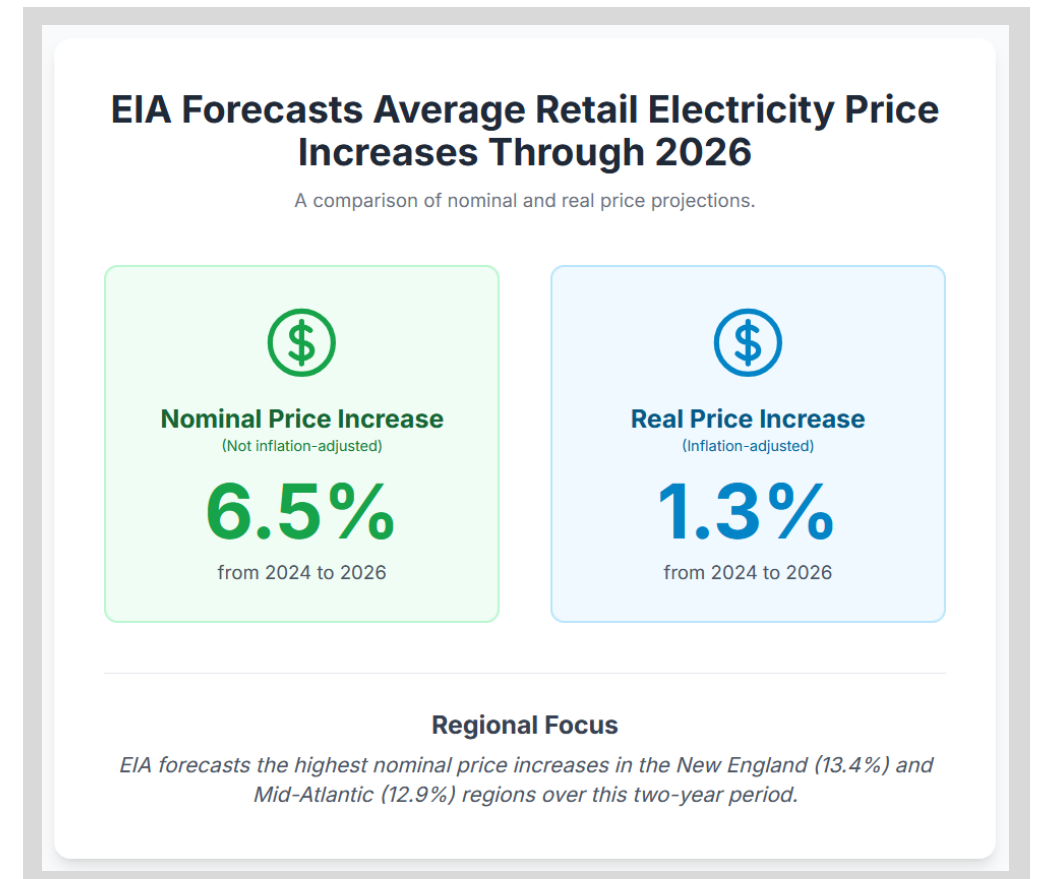
Source: LBNL • Created with Datawrapper

The few states that experienced larger reductions in inflation-adjusted prices did so via lower fuel prices (sometimes from delayed reductions after increase from Ukraine-Russia war).

Note: year-over-year trends are subject to various state ratemaking idiosyncrasies; trends and drivers reported here are therefore, to a degree, unstable.

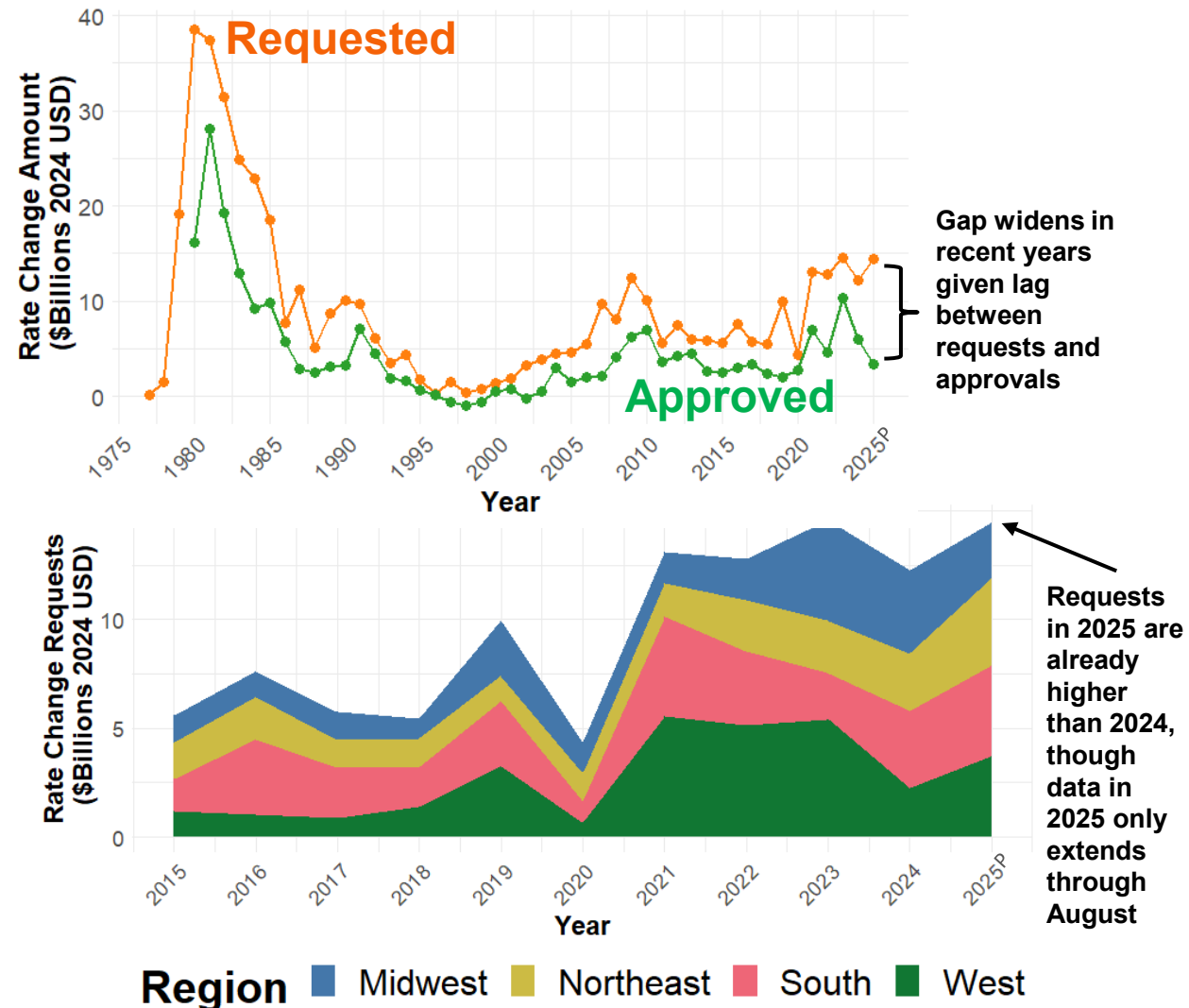
Developments so far in 2025 suggest a continued focus on increasing retail prices and affordability – load growth dominates discussions

- ❑ EIA estimates that prices will increase above inflation in the near term due to load growth and higher gas prices¹; EEI reports an expected increase in utility capital expenditure²
- ❑ Natural gas prices were especially low in 2024 but have since increased—driving up retail electricity prices in many states
- ❑ Grid hardening and costs related to storm recovery and wildfire mitigation are placing upward pressure on prices in many states (East and Gulf coasts, West)
- ❑ Retail prices in some states have trended upward as the market tightens with actual and expected load growth
 - PJM’s high capacity-auction prices are impacting retail prices more-so than suggested on previous slide given the timing of cost pass-through
 - Average electricity bills in New Jersey, Pennsylvania, Maryland, and elsewhere significantly increased in mid-2025³
- ❑ Gas turbines could serve a portion of new load, but the cost of building gas generation has increased significantly in recent years
 - CCGT costs have reportedly escalated from \$1,100-1,300/kW to over \$2,000/kW
 - GE Vernova, Siemens, and Mitsubishi all report long wait times, record backlogs⁴
- ❑ Many other policies and programs at the federal and state levels will impact prices, in uncertain ways
- ❑ Utilities and regulators are developing large-load electricity tariffs to reduce risk that large loads will increase prices for other customers
- ❑ Heightened policy focus on prices and affordability slated to continue in near term, but largest impacts likely to remain regional



Requested rate increases are higher than at any point since the mid-1980s in inflation-adjusted terms, suggesting that price increases will continue

- ▣ Requests in 2025 will end up higher than at any point since the mid 1980s, suggesting more price increases
- ▣ Data collected from S&P Global reflects utility rate change requests back to the late 1970s; however, there are several limitations with only focusing on this dataset:
 - Rate cases mostly involve IOUs; other utility types (e.g. coops, munis) do not file rate cases with state PUCs
 - Rate change requests include base revenue requirements, and include some but not all fuel costs or rate riders
 - Comparing changes before to those after the 1990s will be impacted by restructuring as generation divestiture occurred
 - It's difficult to translate changes in rate requests to a cents/kWh impact given diversity in durations and definitions of requests
- ▣ Nevertheless, these data represent a key signal for changes in underlying utility costs and therefore near-term retail prices
- ▣ Rate change requests in 2025 through August already exceed total 2024 requests and are consistent with 2023
- ▣ Rate changes are correlated with interest rates, with the largest change requests occurring in the early 1980s
- ▣ The regional breakdown appears to be mostly stable over the last decade, though the Western region had a notable increase in portion of rate change increases from 2021-23



Notes: (1) Source: S&P Global, LBNL Analysis; (2) P meant to indicate that only partial data is available for 2025; (3) 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 limited issue rider cases. Fuel cost changes and rate riders are partially but not fully captured.

Managing the new normal: accelerated load growth

- Industry, regulators, and policymakers are exploring various strategies to manage accelerated load growth
- This study makes no effort to evaluate or summarize those strategies comprehensively
- As one example, Brattle recently published a [report](#) that highlights the importance of optimizing existing grid infrastructure and proactive planning to support new infrastructure
- Graphic to right highlights some of the report’s key findings, and includes actions related to:
 - Maximizing the value of the existing power system
 - Accelerating grid connection of new loads
 - Planning to accelerate new investment
 - Targeted affordability measures
- Brattle report provides an illustration of possible responses; no claim of comprehensiveness

	Solutions	Regulators	Utilities	Grid planners / operators	Governors and Legislators	Others
Maximize the Value of the Existing Power System (Section III)	A. Enable distributed and demand-side resources	✓	✓	✓		Third-party DER aggregators
	B. Enhance rate options	✓	✓		✓	
	C. Utilize GETs, ATTs, and RASS	✓	✓	✓	✓	
	D. Capitalize on transmission upsizing opportunities	✓	✓	✓		
	E. Facilitate interregional trade			✓	✓	
Cost-Effectively Accelerate the Grid Connection of New Loads (Section IV)	A. Enable customer-sponsored generation	✓	✓	✓	✓	
	B. Co-locate new generation and load	✓	✓	✓	✓	Energy park developers
	C. Streamline generator interconnection processes	✓	✓	✓		Transmission owners
Implement Proactive Planning and Procurement Processes to Accelerate the Necessary Investments (Section V)	A. Proactively plan generation and transmission	✓	✓	✓	✓	Power procurement authorities; State energy offices
	B. Reform generator procurement processes	✓	✓	✓	✓	Power procurement authorities; State energy offices
	C. Proactively plan distribution systems	✓	✓			
	D. Improve load interconnection processes	✓	✓		✓	State energy offices
Introduce Targeted Affordability Measures (Section VI)	A. Offer energy efficiency and bill assistance	✓	✓		✓	State energy offices
	B. Implement specialized rates for new large loads	✓	✓		✓	
	C. Explore alternative financing	✓	✓		✓	Private developers

Research, data, and engagement gaps

Much remains to be fully understood: possible future analyses of *historical* retail electricity price trends and drivers could include...

Statistical analysis and case studies to disentangle various effects and determine their relative influence

- **Statistical analysis** could focus on states, utilities, and/or different customer classes → each would provide different insight
- Analysis could be designed to determine relative size of **multiple factors**, or offer detailed assessment of **individual factors**
- Given limits to broad-based statistics, more **case-study assessments** may be needed if focused on individual states

As part of the above, it would be valuable to include the drivers described earlier, and augment them

- **Customer-side resources**: explore impacts of electric vehicles, demand response, VPPs, efficiency, advanced metering, etc.
- **State policies**: explore possible impacts of a wider variety of state policies and programs
- **Generation**: expand scope beyond wind, solar, and natural gas to include coal, storage, and other supply sources
- **Reserve margins**: explore impact of market “tightness” on retail prices
- **T&D**: more comprehensively explore the drivers of T&D costs and how that impacts retail rates
- **Market structure**: wholesale & retail competition, vertical integration, investor- vs. public ownership (& rate of return for IOUs)

Deeper assessments of specific drivers and impacts given their importance for future outcomes

- **Load growth and flexibility**: under what conditions does load growth and flexibility increase vs. decrease retail prices
- **T&D costs**: contribution of various factors influencing costs; conditions under which investment may reduce retail prices
- **State policies (beyond RPS)**: low-income assistance, cap-and-invest, stranded assets, nuclear, etc.
- **Cost allocation**: drivers and impacts of cost allocation decisions as it related to price difference by customer class
- **DOE supported technologies**: historic impact of DOE-supported technologies on retail prices

Broader gaps and opportunities for insight

Future price drivers

- modeling to assess possible future drivers of retail prices, consistency with past

Customer energy bills

- focus not only on electricity prices, but on energy bills (electricity, heating, transport)

Ratepayers vs. taxpayers

- extent to which costs are (or should be) covered by ratepayers vs. taxpayers

Value for money

- how to trade off affordability vs. reliability and other benefits when making decisions

Data gap for POUs

- more-granular data for publicly-owned utilities, similar to FERC Form 1 for IOUs

DOE impact assessment

- assessment of possible impact of DOE investments on future retail prices

Tool development

- many existing tools poorly estimate distribution costs, therefore impacts on retail prices

Educational opportunity

- visualize ratemaking: various costs → revenue requirement → cost allocation → rates

Rate decomposition

- as part of above “education”, explore changes over time for selected utilities



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