Rates, Returns, and Regulation: *What's the Buzz?*

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National Association of State Utility Consumer Advocates Mid-Year Meeting
July 21, 2026

This presentation was funded by the U.S. Department of Energy's Office of Electricity, under Contract No. DE-AC02-05CH11231.

Public attention is high on issues related to electricity prices and affordability

Soaring Electricity Costs Are Now a Hot Political Issue

AI data centers are sending power bills soaring

Corporate Greed at Its Worst: Top US Utility Giants Reap $14 Billion in Profits as Households Suffer

Looking Ahead to a Deepening Affordability Crisis

Price shock: Demand from data center boom raises electricity bills

Don't Blame Renewable Energy for Escalating Electricity Costs

Senators count the shady ways data centers pass energy costs on to Americans

U.S electricity prices climb to a new record… as gas costs fuel grid strain

Don't blame data centers for high energy prices – blame Democrats

A Simple Fix to America's Soaring Electricity Prices

Green energy is making electricity more expensive for Americans

Why Trump and Democrats are wrong about rising electricity prices

Why the Price of Electricity Is Spiking Around the Country

There's a reason electricity prices are rising. And it's not data centers.

Add nuance to discussions about the “affordability crisis” and the scapegoating that often occurs when identifying causes of that “crisis”

Summarize recent retail electricity price trends	Assess drivers of recent retail electricity price changes	Identify opportunities to mitigate future price increases
• National- and state-level price trends, since 2010, 2019, and 2024	• Most-likely drivers of state-level price changes, 2019-2025 and 2024-2025	• Regulatory options in the short-term and medium-term

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Retail Electricity Price Trends and Drivers: Data Update–2026 Edition.

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April 2026

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

Image source: OpenAI DALL-E

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Electric Utility Distribution Costs

Scoping study on trends, drivers, and possible response strategies

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Lawrence Berkeley National Laboratory

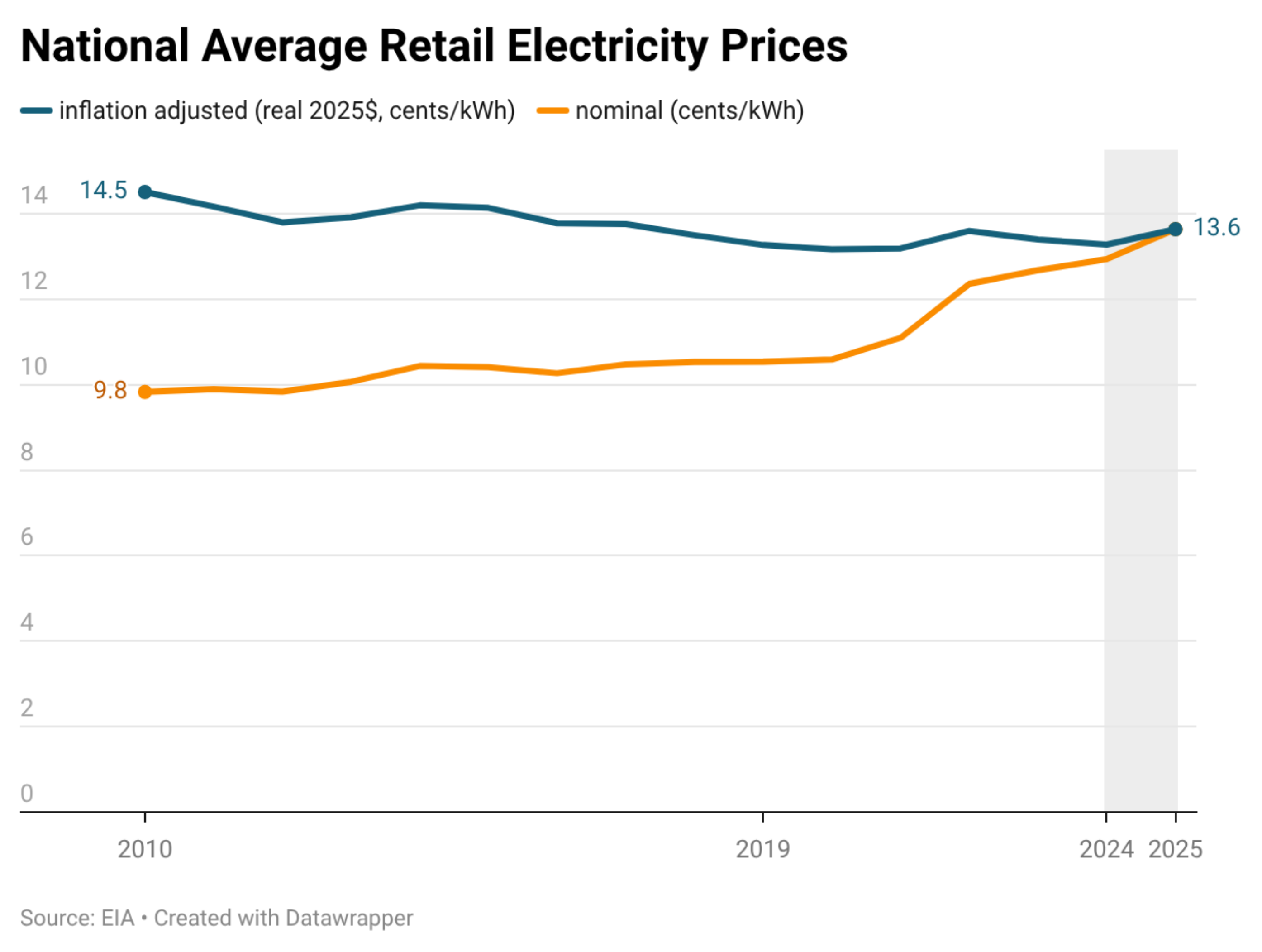
May 2026

This work was funded by the U.S. Department of Energy's Office of Policy, under Contract No. DE-AC02-05CH11231.

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

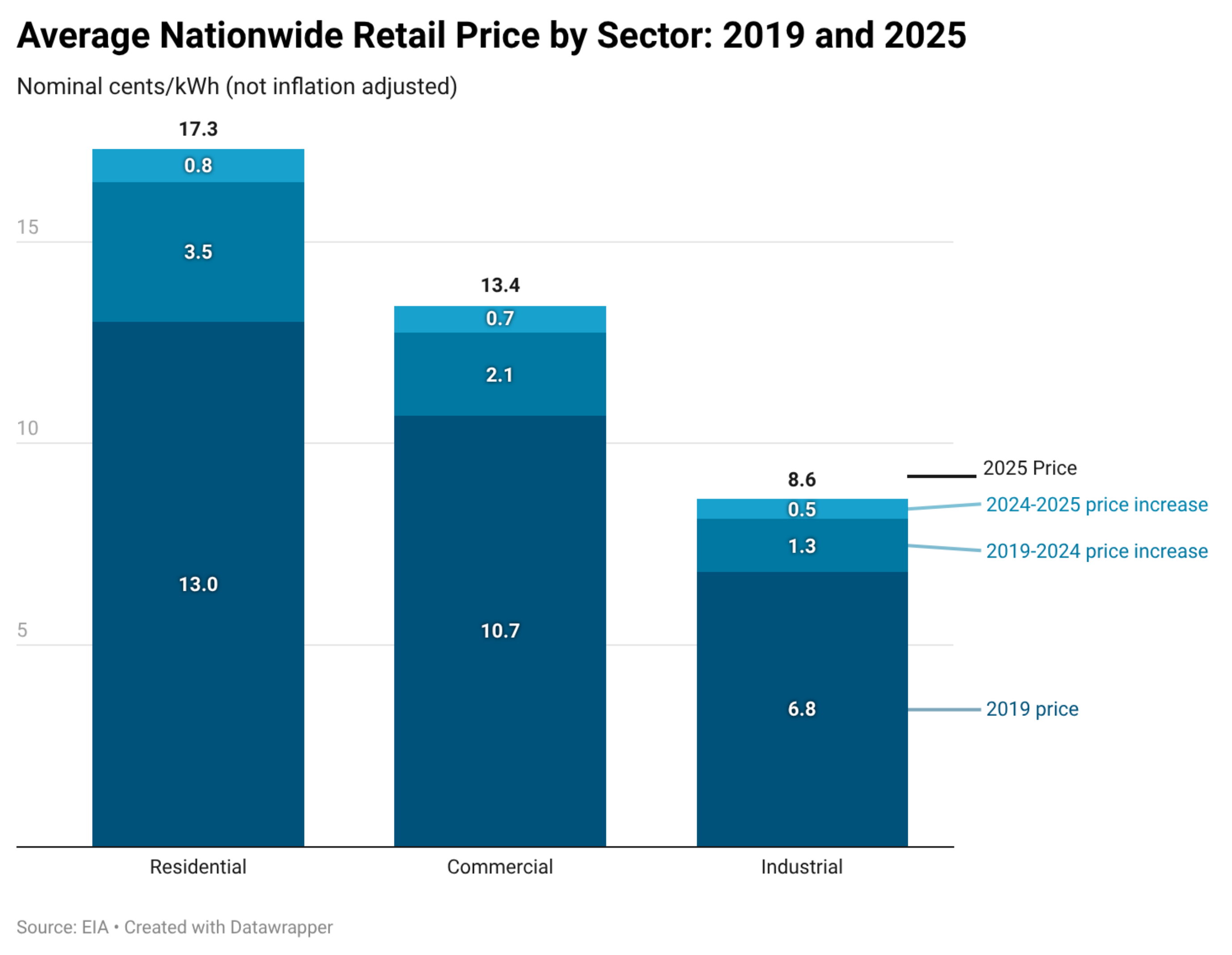
- All-sector average retail prices <u>increased in 2025</u>
  - **5.3%** in nominal terms, **2.6%** in inflation-adjusted terms
- <u>On a longer-term basis:</u>
  - In nominal terms, avg. prices increased **29%** from 2019 to 2025, and **39%** since 2010
  - Adjusting for inflation, prices in 2025 were **3% higher** than 2019, **6% lower** than 2010

Represents the "all-in" price, equivalent to total customer bills (including volumetric, demand, and fixed charges) divided by total retail electricity sales



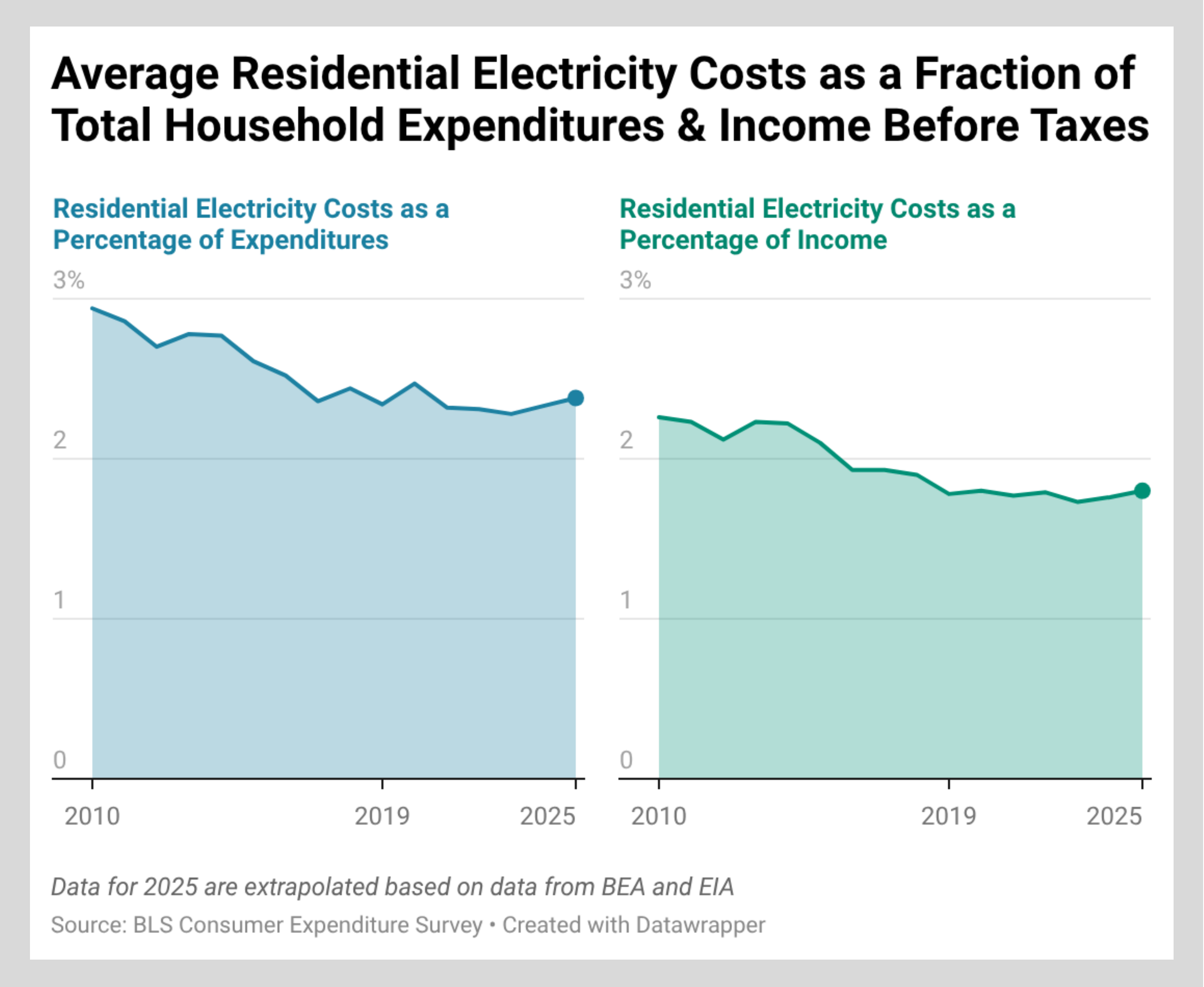
Residential customers have faced larger recent retail electricity price increases than have commercial and industrial customers

- Residential prices are higher, have generally risen faster than commercial & industrial (C&I)
- From 2019 to 2025 (nominal):
  - Residential up: 33%
  - Commercial up: 26%
  - Industrial up: 27%
- Residential prices up 6% in real dollars since 2019, compared to 3% for all-sector average
- Continues a longer-term trend of increasing gap between residential and C&I prices



National residential electricity bills as a fraction of household expenditure *(left)* and income *(right)* trended down for decades, but increased recently

- Average residential bill as a fraction of total expenditure
  - 2.4% in 2025
- Average residential bill as a fraction of income before taxes
  - 1.8% in 2025
- In both cases, 2025 values:
  - are lower than in 2010,
  - are near all-time lows,
  - but are similar to 2019,
  - and have increased since 2023.



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

- "Electricity burden"[1]: Nationally, residential bills as fraction of income **have generally declined** since 2010, with recent increase
- Regardless of trends, **average electricity burdens are > 5% for lower-income households** *(~1/3 of households are <$50k)*, and have (likely) increased in 2025
- Additional signals of challenges:
  - 1-in-6 households are behind on their energy bills; utility arrearages = $21 B in May 2025[2]
  - Among 92 utilities, disconnection rates declined from 2019 (~0.4%) to 2020 (~0.1%); have since increased through 2024 and are approaching pre-COVID levels (~0.3%)[3]

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

Electricity burden for average household in each income bracket

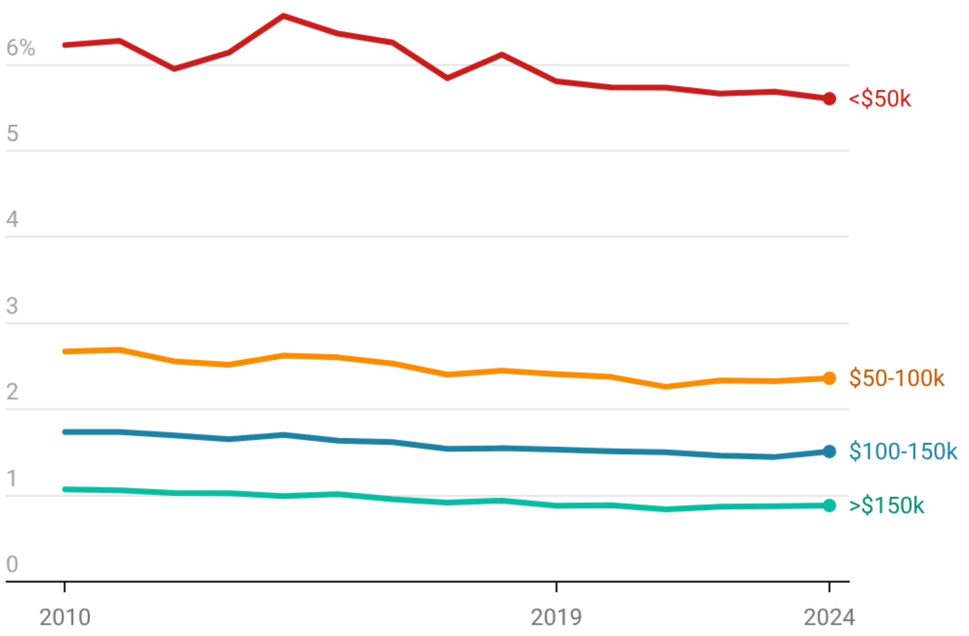


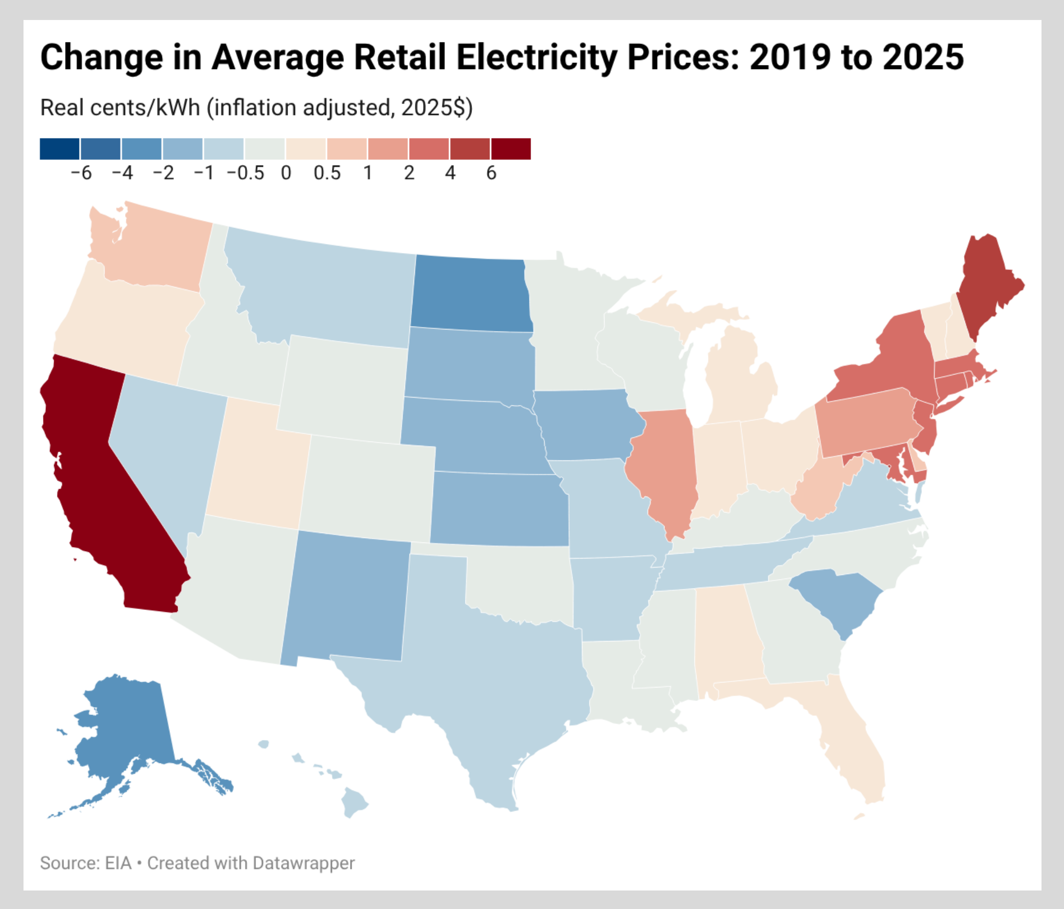
Figure excludes the bottom and top quartiles of data in each income bin to create more stable results. Data are from the BLS Consumer Expenditure Survey. Electricity costs are based on respondent reports of costs over three-month periods and therefore likely entail some degree of recall error. Further,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

Source: BLS • Created with Datawrapper

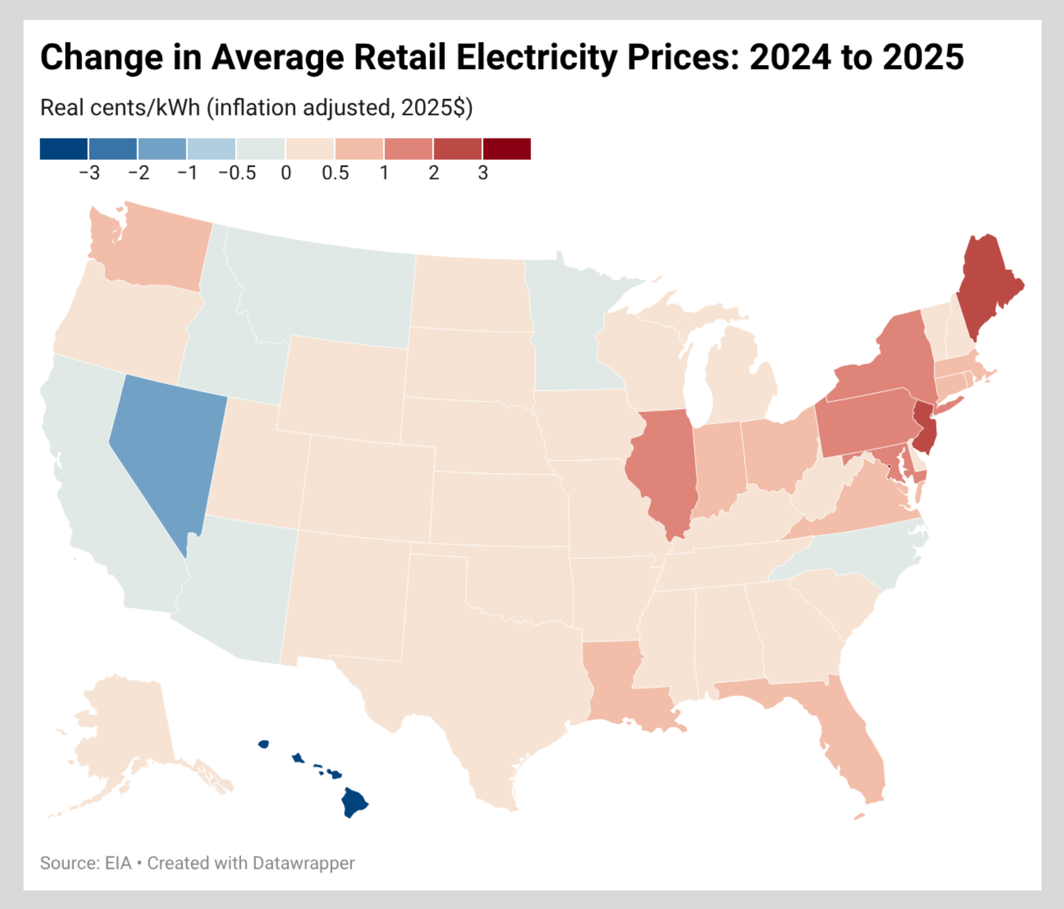
[1] *Focused solely on electricity impacts, not broader concept of energy burden;*
[2] NEADA (2026); [3] Carley & Konisky (2026)

National trends mask stark differences in changes in state-level all-sector average retail electricity prices from 2019-2025 *(left)* and 2024-2025 *(right)*

2019-2025: 29 states with decreases, but with large increases in California, Northeast, some states in Mid-Atlantic, West, Great Lakes

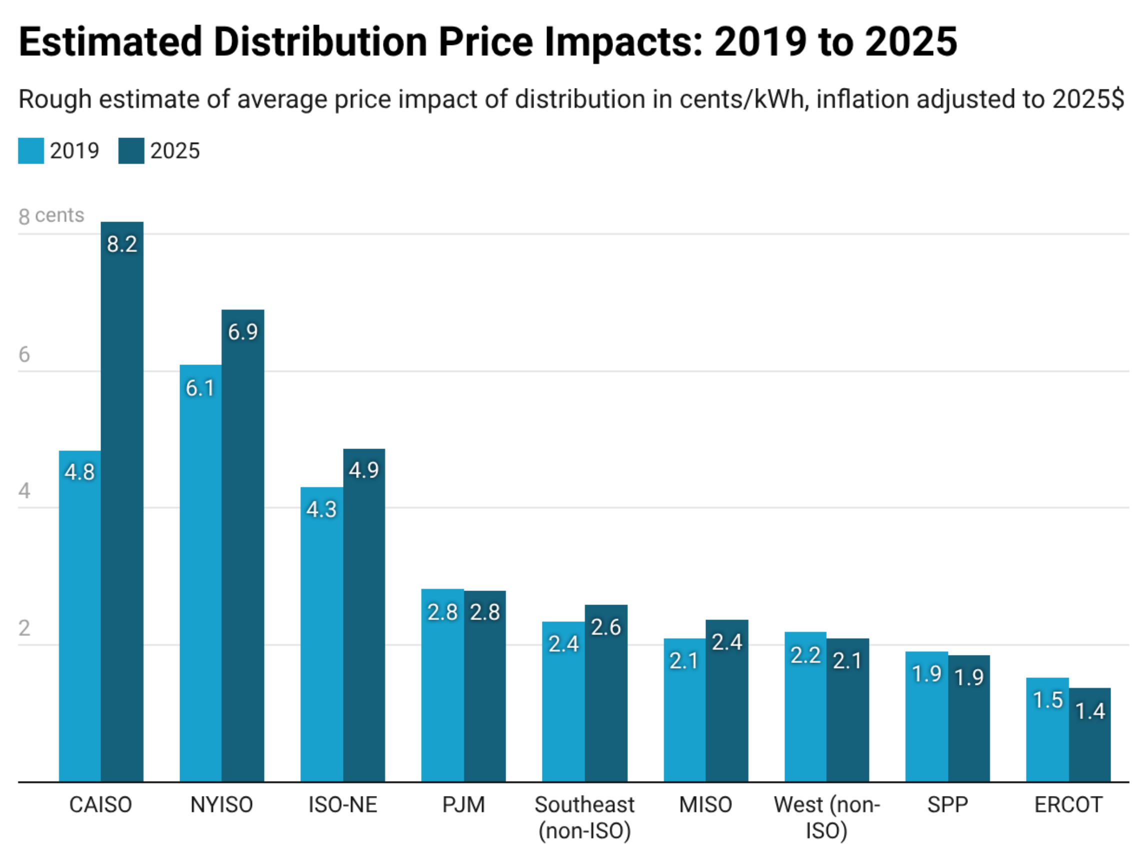


2024-2025: 43 states/DC with increases; largest increases in Northeast, Mid-Atlantic, Great Lakes, some in Southeast and West

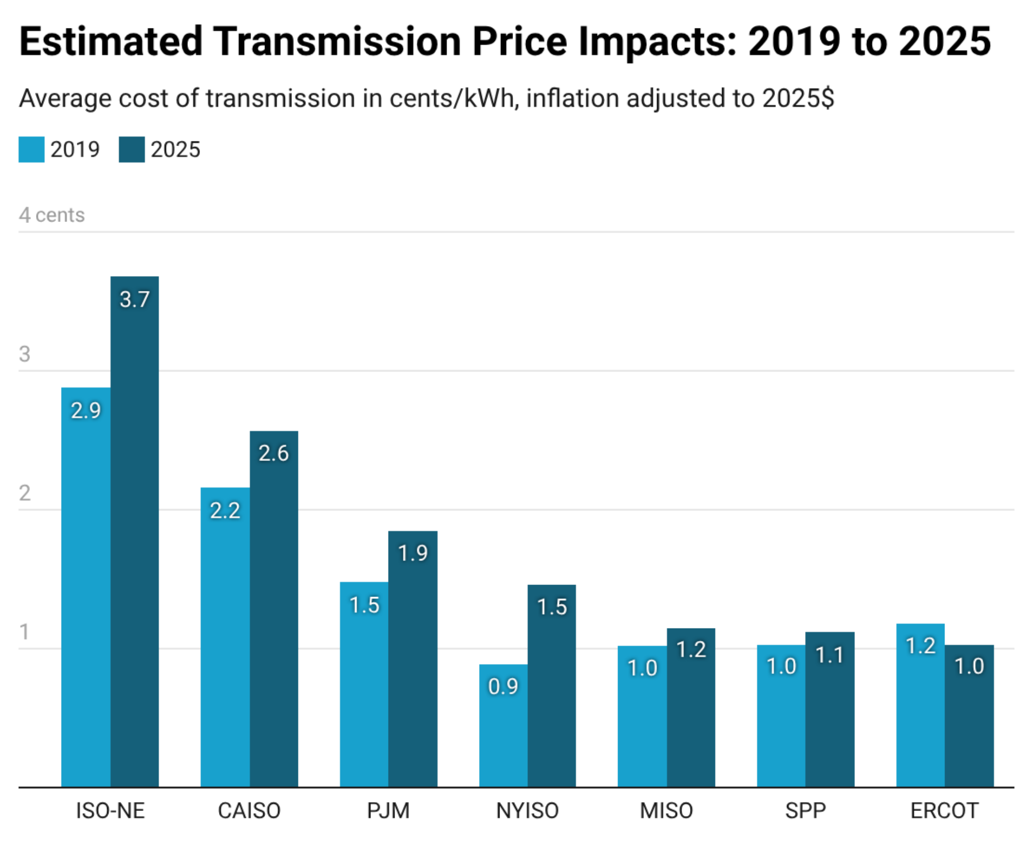


T&D expenditures contributed to retail price increases from 2019 to 2025, especially in California, New England, New York, Mid-Atlantic

ESTIMATED IMPACT OF DISTRIBUTION ON ALL-SECTOR AVERAGE PRICES



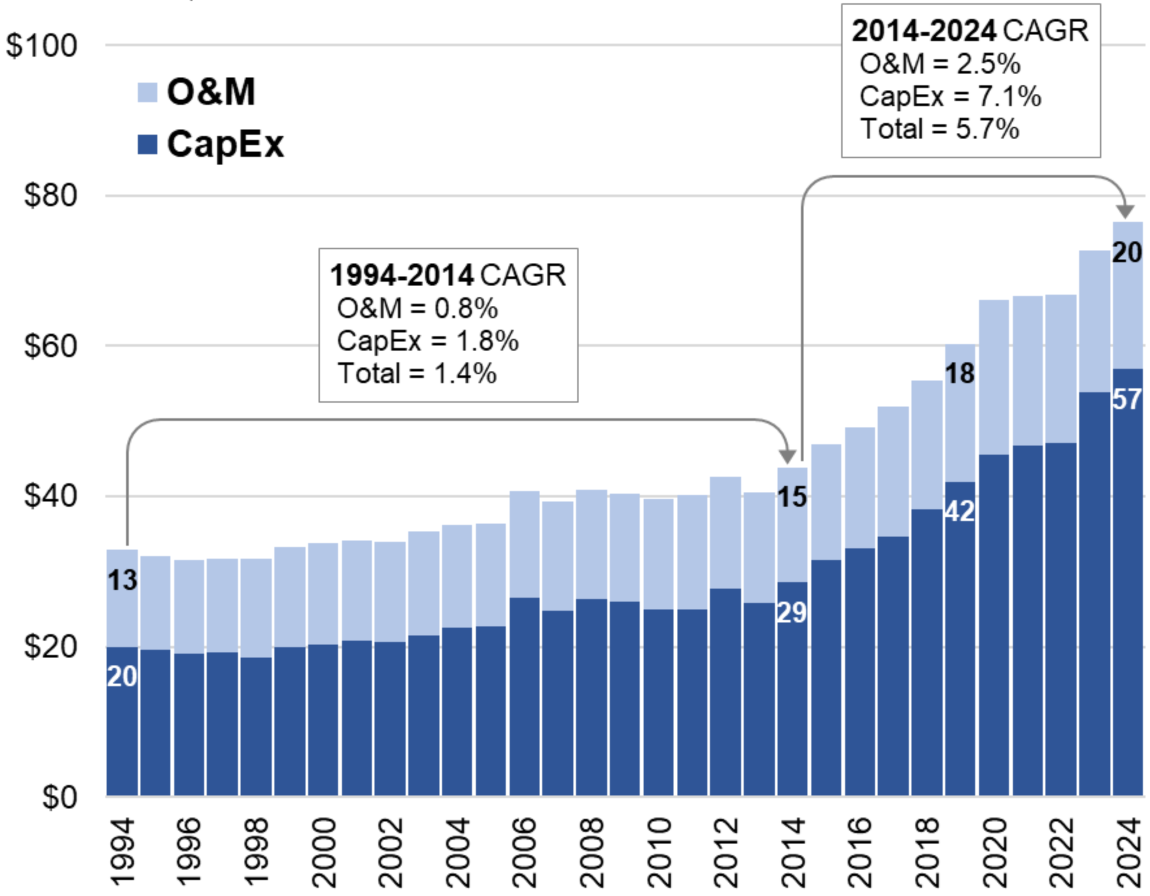
DIRECT IMPACT OF TRANSMISSION ON ALL-SECTOR AVERAGE PRICES



Total IOU distribution spending has been growing rapidly over the past decade, driven mostly by growth in CapEx

- Total U.S. IOU distribution system spending hit an inflection point in ~2014: since then, spending has been **rising ~4x faster** (in real dollar terms) than the prior 20 years, despite virtually flat load growth, nationally
- Trends over the past five years (2019-2024) have continued along the same trajectory, but for the pandemic-era lull from 2020-2022
- Both CapEx and O&M spending have grown, at least at a *national* level, but CapEx has been the major contributor: e.g., since 2014, **CapEx grew by $27.6 billion** compared to **$4.1 billion growth in O&M** expenses
- However, while O&M is recovered in rates annually, CapEx (and associated financing) costs are recovered over many years

Annual U.S. Electric IOU Distribution Expenditures
billions 2025$



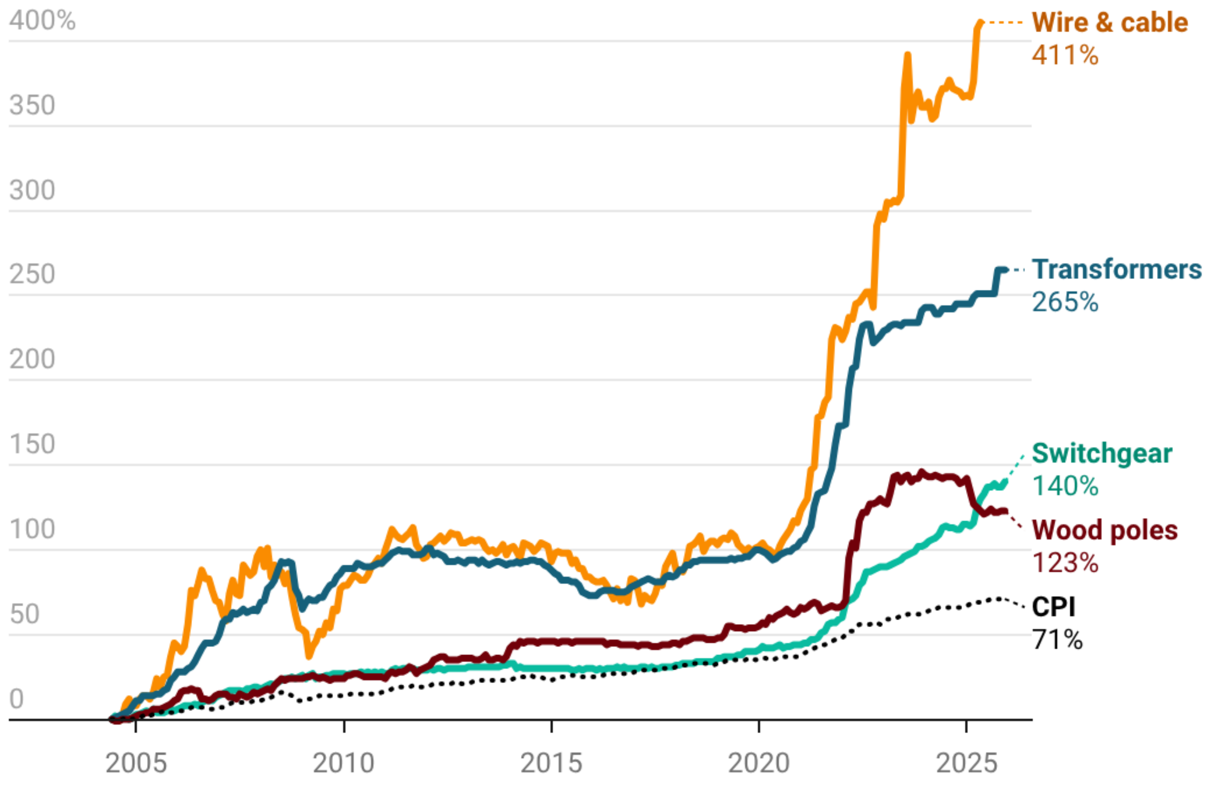
Notes: O&M values are based on distribution expenses reported on the Electric Operations and Maintenance schedule. CapEx is based on distribution additions from the Electric Plant in Service schedule.

One of the reasons for recent growth in distribution CapEx is that equipment prices have grown well-above the pace of inflation

- **There are multiple drivers for CapEx growth:** In 2025, EEI reports that 33% of investment was driven by "adaptation, hardening, and resilience," 28% for "replacement", and 31% for "expansion"[1]
- Regardless of the cause, post-pandemic **supply-chain constraints and elevated equipment prices** contributed to recent distribution CapEx increases
- The figure shows producer price indices for distribution-related products, contrasting those with the CPI
- Price indices for some equipment have moderated somewhat in recent years, but prices since 2021 increased much faster than CPI and remain elevated

Producer Price Index for Power System Equipment

Shown as percentage change relative to June 1, 2004, also compared to CPI



Source: BLS, FRED • Created with Datawrapper

[1] EEI (2025)

For some states and utilities, costs associated with *storms and wildfires* have also significantly contributed to electricity price increases

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

Recent Estimates of Utility Storm Recovery Price Impacts

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

Source: LBNL • Created with Datawrapper

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

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

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

Recent Estimates of Utility Wildfire Mitigation Costs

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

Source: LBNL • Created with Datawrapper

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

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

A utility's authorized ROE is an important component of its revenue requirement, and is informed by estimates of its cost of equity (COE)

- Regulator approved utility revenue requirements and rates include an **authorized ROE** that gives utility shareholders an **opportunity to earn a return on investments** comparable to other enterprises with similar risks
  - The **achieved ROE** is affected by firm-specific opportunities and risks that affect costs and revenues between rate cases
- The **COE** represents the **unobservable returns investors expect to earn** on stocks facing similar risk as a utility
  - The **COE** is affected by non-firm specific opportunities and macroeconomic risks

Characteristic	Achieved ROE	Cost of Equity
Type of Return	Accounting variable	Market expectation
Perspective	Utility	Investor
Source	Observable	Estimated
Reference	Financial statements	Expected returns on other companies' stocks
Relevant Risks	Affected by many firm-specific risks	Affected by only a few macroeconomic risks
Relation to Stock Price*	Positive correlation	Negative correlation

* Assumes all other factors are held constant.

Source: LeBel et al. 2023

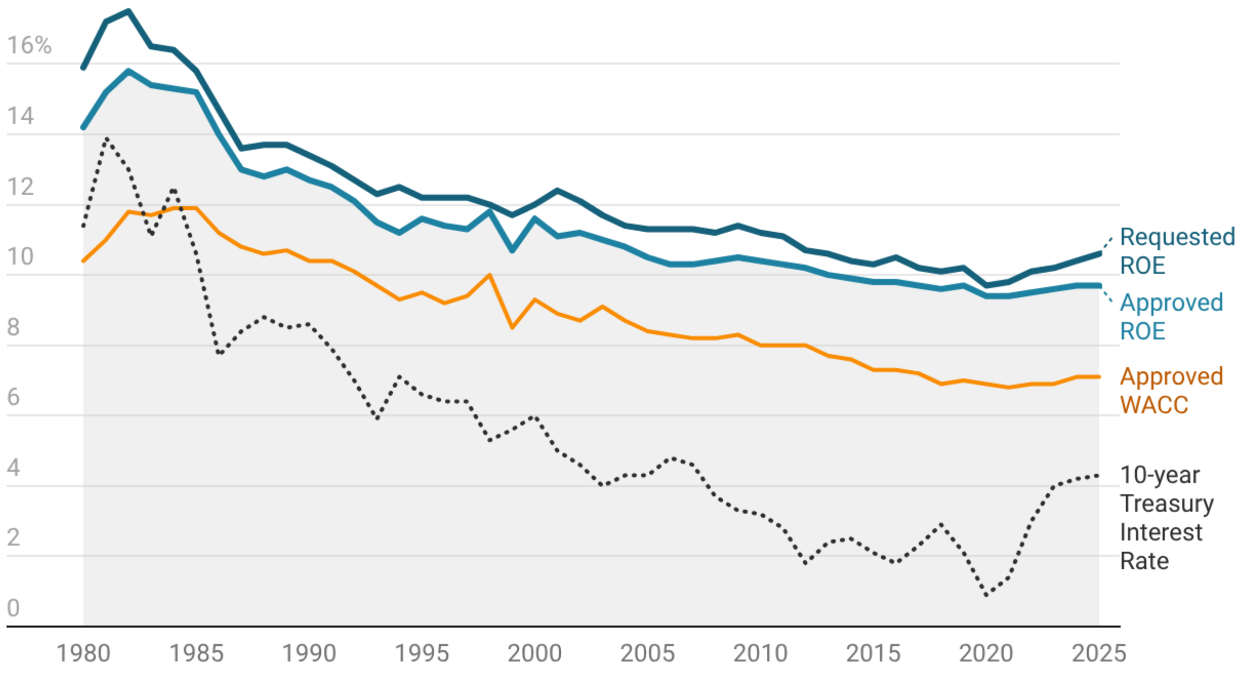
- The **COE** can be thought of as **the minimum achieved ROE** that a hypothetical shareholder requires, and is often estimated as part of the regulatory process that establishes **authorized ROE**
- If **achieved ROE>COE**, then utility stock prices increase & **wealth is created** for current shareholders; if **achieved ROE<COE**, then utility stock prices decrease & **wealth is destroyed** for current shareholders

Requested and authorized ROEs have increased over the last 5 years, as have approved WACCs, but remain low by historical standards

- Interest rates are a key factor in estimating a utility's cost of equity and are largely driven by inflation rates
- Requested ROE levels are correlated with 10-Year Treasury interest rates
- Avg. **requested ROE** in 2025 = **10.6%**
- Avg. **authorized ROE** in 2025 = **9.7%**

Requested and Approved IOU Return-on-Equity, Approved WACC, and Relationship to 10-year Treasury Interest Rate

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



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

Source: S&P Global • Created with Datawrapper

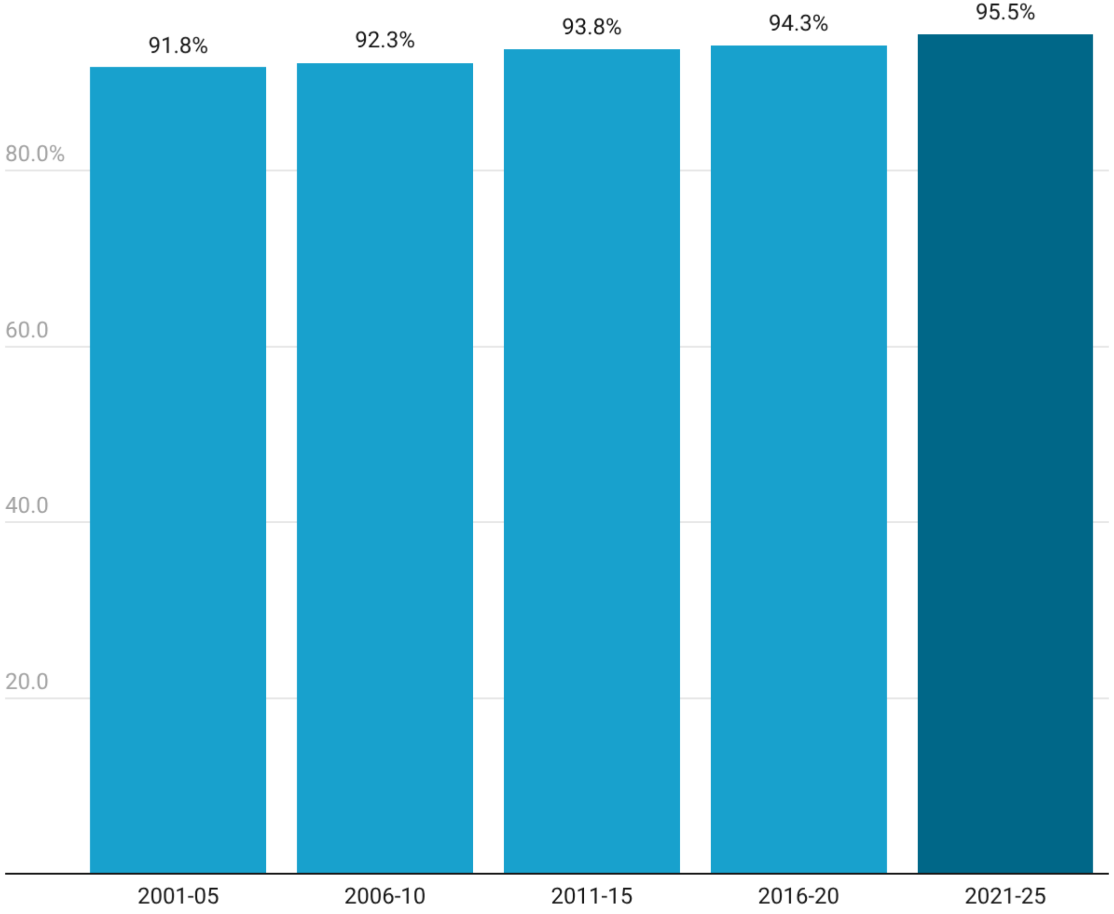
Note: Sample of 1,263 ROE requests and 1,045 ROE approvals in the 2001-2025 period are presented in this graph, along with 1,027 ROE requests and 989 ROE approvals in the 1980-2000 period.

Regulators have authorized utility ROEs at a lower discount from utility requests over the last 5 years than in previous years

- PUCs have generally authorized utility ROEs that are modestly discounted from utility requests, with those discounts declining slightly over time
- Over the last five years, PUCs have, on average, authorized ROEs at **95.5%** of initial requests (4.5% discount)*
- This is up from an average of **94.0%*** from 2011-2020 and **92.1**%* from 2001-2010
- Higher ROE approvals could imply, e.g.: more-defensible initial ROE requests; lower-levels of scrutiny on requests; other changes in overall environment

Regulatory Approval Levels for IOU ROE Requests

Approvals as a percent of ROE requests: average across all requests

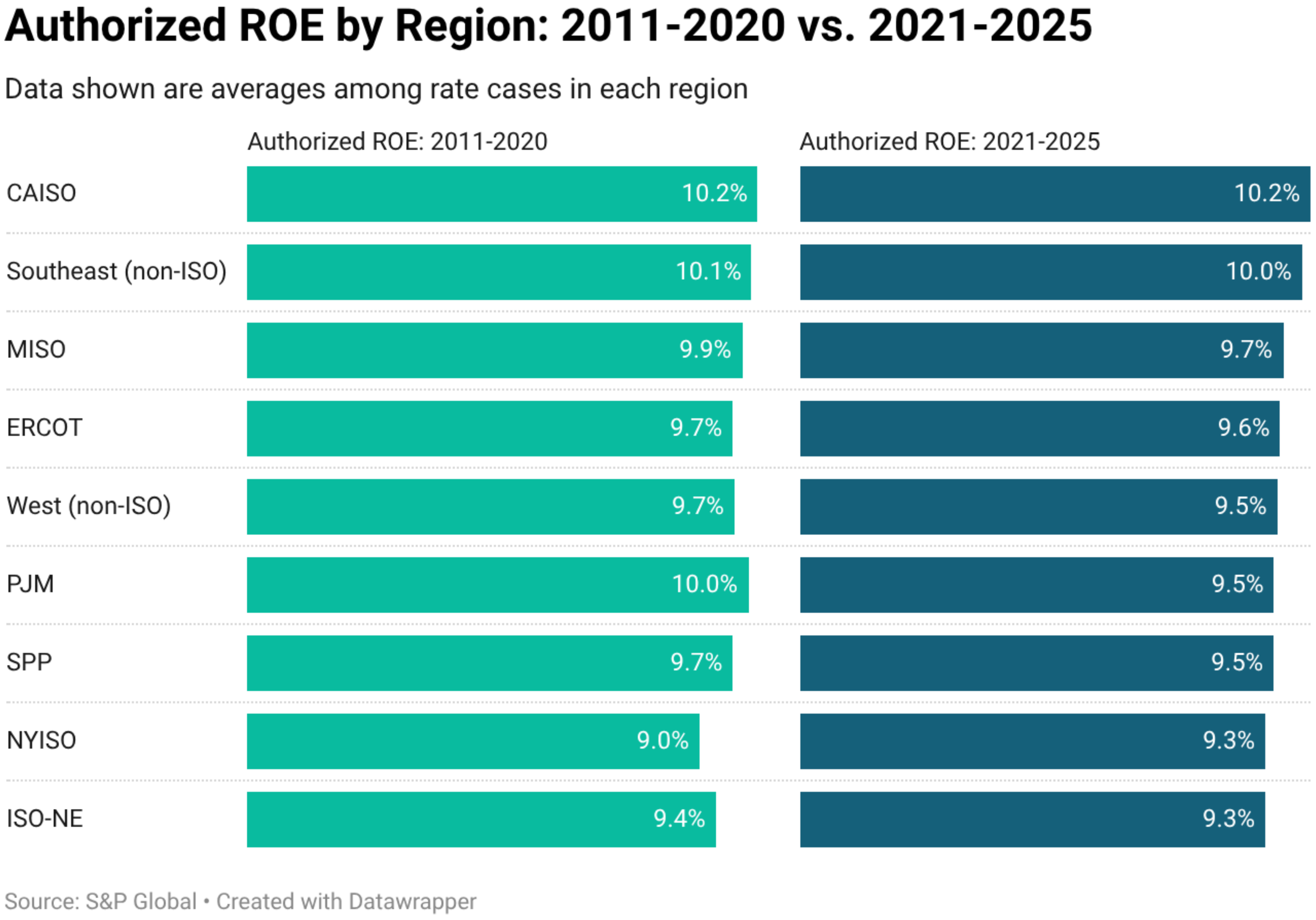


Source: S&P Global • Created with Datawrapper

*Corresponds to absolute ROE reductions of 0.47% (2021-25), 0.64% (2011-20), and 0.93% (2001-10)

Recently authorized ROEs vary by region: highest in California and the Southeast, lowest in New England and New York

- Authorized utility ROEs have recently been the **highest in California & Southeast: greater than 10%**
- Recently, authorized ROEs have been the **lowest in New England & New York: 9.3%**
- Most regions saw slight reductions in authorized ROEs from 2011-2020 to 2021-2025
- Exceptions are CAISO (flat ROEs) & NYISO (increased ROEs, but still relatively low)



Empirical evidence suggests that historical authorized ROE values exceed COE → and thus could lead to a "capital bias"

- There is debate on how close authorized ROE should be set relative to COE
  - NARUC manuals suggest authorized ROE should equal COE, so utilities are indifferent as to whether they expand CapEx vs. OpEx
  - Others argue that ROE may appropriately be set higher than COE to incentivize efficiency and innovation (Kahn, 1988); regulators may also desire a cushion to encourage investment when needed to meet load growth or ensure reliability; however, an ROE that exceeds the COE could lead to an overinvestment by the utility in capital projects vs. OpEx (i.e., Averch-Johnson effect)
- Empirical evidence suggests that many IOUs have authorized ROEs that exceed COE estimates *(see text box to the right)*
- If true, leads to higher retail prices and incentivizes CapEx over OpEx

Key Literature Providing Empirical Evidence

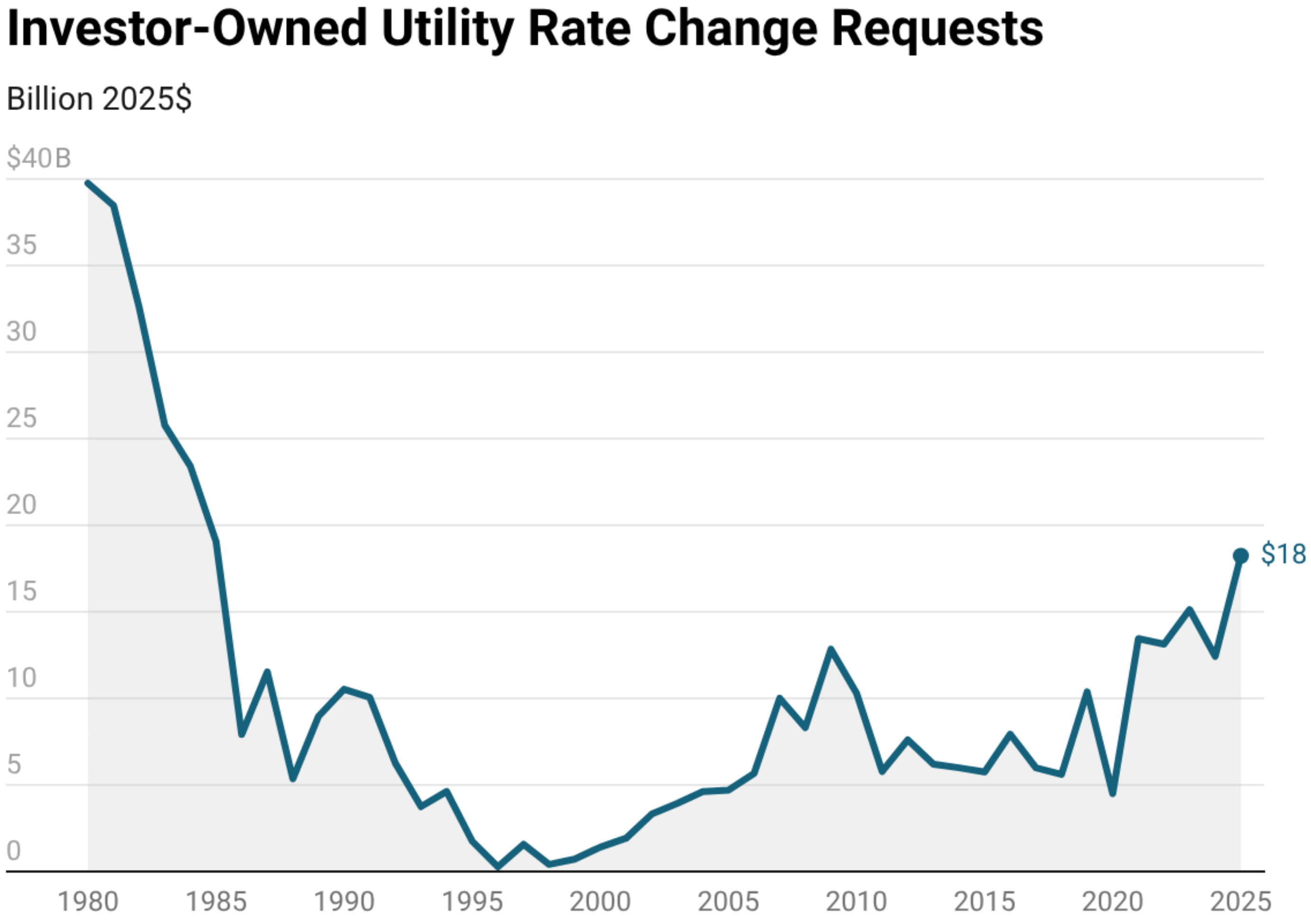
1. Werner & Jarvis (2025), "Rate of Return Regulation Revisited," SSRN
   - Average excess ROE (over COE) estimated at between 2-5% over last 3 decades
   - 1% excess in ROE level estimated to lead to 3-4% increase in capital assets, **predominantly in distribution grid investments**
2. Ellis (2025), "Rate of Return Equals Cost of Capital: A Simple, Fair Formula to Stop Investor-Owned Utilities From Overcharging the Public," *AELP*
   - Market-to-book ratio of utility stocks ~2 over last 15 years, suggesting authorized ROEs could be close to 1.5x more than market-based COE
   - Authorized ROEs are ~3% higher than average U.S. stock equity returns
3. Daniel et. al. (2025), "Rebalancing "Return on Equity" to Accelerate an Affordable Clean Energy Future," *Rocky Mountain Institute*
   - Market-to-book ratio of utility stocks ~1.81, suggesting ROE is well above COE
4. Rode & Fischbeck (2019), "Regulated equity returns: A puzzle," *Energy Policy*
   - Growing ROE premium from ~3% in 1980s to ~6.7% in 2018
5. Myers & Boruki (1994), "Discounted Cash Flow Estimates of the Cost of Equity Capital," *Financial Markets, Institutions, and Investments*
   - Found that authorized returns on equity exceeded properly estimated costs of equity for virtually all utilities studied

Many reasons have been posited to explain potential ROE premiums; reducing them could generate bill savings for utility customers

If this premium could be reduced, the aggregate ratepayer cost implications have been estimated to be meaningful:

Utility rate increase requests have increased in recent years and they hit a multi-decadal record in 2025, last surpassed in the early 1980s

- IOU rate increase requests in 2025 = **$18.2 billion**
- Rate increase requests in 2025 exceeded any point since mid-1980s in inflation-adjusted terms
  - 1980s spike due in part to high interest rates, investments related to expected load growth, cost over-runs
  - Load growth was substantial from 1980-2000, but it is difficult to separate growth impacts on rate requests from interest rate, cost over-run, and regulatory restructuring
- Note: Following slides focus on 2001-2025 to emphasize more-recent period over which comparisons are more stable



Source: S&P Global • Created with Datawrapper

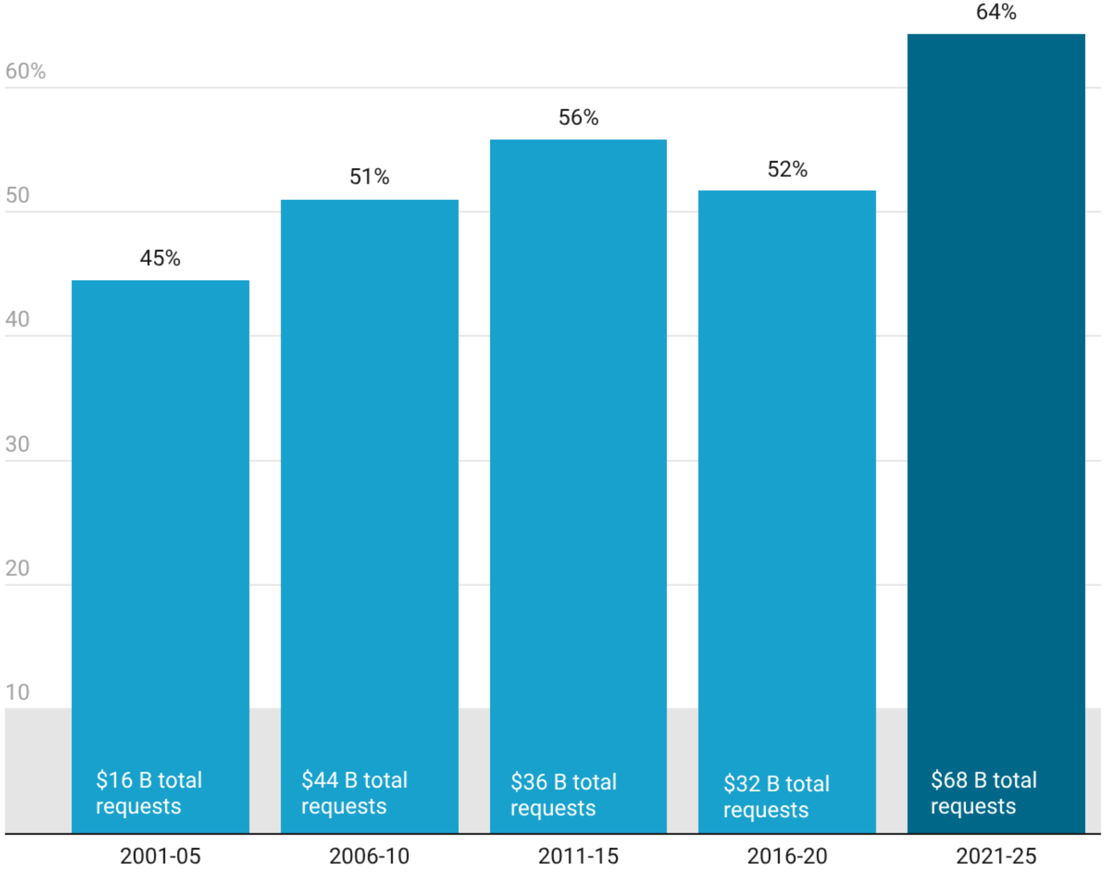
Count of rate cases in sample				
1981-90	**1991-00**	**2001-10**	**2011-19**	**2021-25**
667	274	412	649	404

Regulators have approved a higher percentage of utility rate increase requests over the last 5 years than in previous years

- Over the last five years, public utility commissions (PUCs) have, on average, approved **64%** of rate increase requests
- This is higher than in the previous two decades, during which the average approval percentage was **52%**
- Higher approval percentages could imply, e.g.: more-defensible rate increase requests; lower-levels of scrutiny on requests; other changes in overall operating environment
- Regardless of cause, high IOU requests in 2025 plus high levels of regulatory approval suggest upward price pressure in the near-term barring load growth that exceeds increases in revenue requirements

Regulatory Approval Levels for IOU Rate Increase Requests

Approvals as a percent of rate increase requests



Data presented as averages, with each request weighted by its size. Total request amounts are in 2025$.

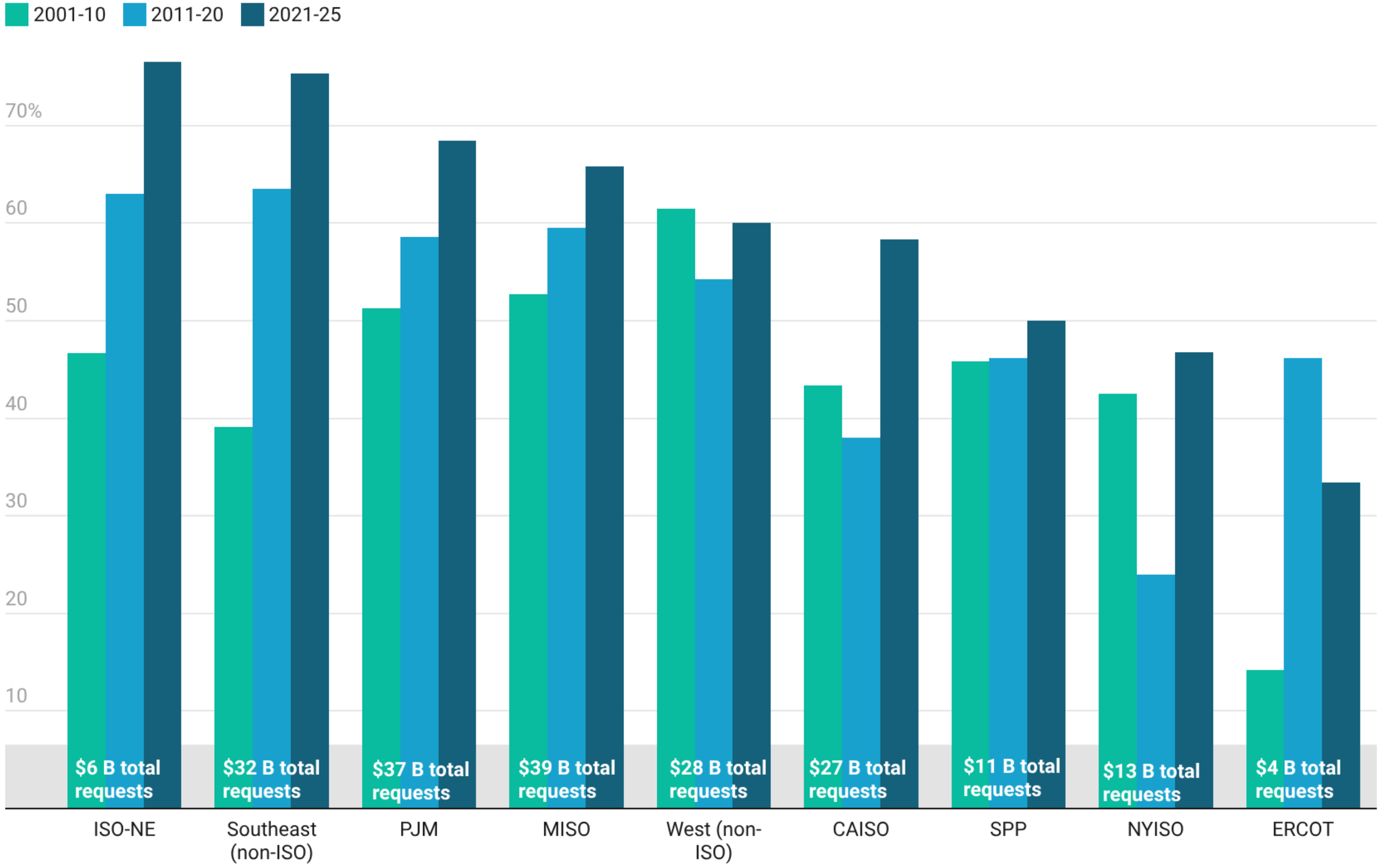
Source: S&P Global • Created with Datawrapper

Approval percentages in most regions are higher than in the past: New England and the Southeast have approved higher fractions of requests

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

Regulatory Approval Levels for IOU Rate Increase Requests, by Region

Approvals as a percent of rate increase requests



Data presented as regional averages, with each request weighted by its size. Total request amounts are for 2001-2025 in billion 2025$.

Source: S&P Global • Created with Datawrapper

Short term

Reduce impacts of return on equity and asset cost recovery

Incentives and Financing

1 Reduce approved return on equity (ROE)

- IOUs must have a reasonable opportunity to earn a return on investments comparable to other enterprises with similar risks
  - But an ROE above the cost of equity unnecessarily raises rates and creates an incentive to invest in capital solutions
- Regulators can determine an appropriate lower ROE in rate cases, particularly if mechanisms like trackers and CWIP transfer risks from utility shareholders to their customers
  - Utilities are concerned that credit rating agencies may downgrade ratings—making it harder to attract capital, increasing cost of debt
  - If so, retail rates may be lower or higher depending on degree

3 Change depreciation rates if appropriate

- In addition to shareholder return and interest paid on capital assets, utilities are allowed cost recovery for those assets
- Longer asset recovery period → lower near-term (but higher long-term) rate impacts; salvage value also impacts results
- Asset lifetimes are an empirical question but also uncertain; there is regulatory discretion to determine appropriate rates based on utility depreciation studies, staff analysis, testimony

2 Determine appropriate capital structure

- The average capital structure of U.S. regulated electric utilities is split evenly between debt and equity
- Debt usually costs less than equity
  - Bondholders bear less risk—they get paid before stockholders receive dividends
  - Utilities (and customers) pay taxes on ROE; utilities get tax deductions for interest payments on debt
- Higher debt/equity ratio reduces required revenue
- Rate cases set utility capital structure for retail rates, and regulators can determine a capital structure that is different than what the utility requests (e.g., if proposed debt/equity ratio is inappropriately low)

Examples

- California PUC lowered ROE by 0.3% in 2025 for large IOUs
- Utah PSC reduced Rocky Mountain Power’s requested equity portion from 50% to 44.43%

Medium term

Adopt performance-based regulation (PBR)

Incentives and Financing

- PBR strengthens utility incentives for cost containment
  - *Multi-year rate plans* (MRP) are expressly designed to contain utility costs by reducing the frequency of rate cases to 3–5 years
  - Attrition relief mechanisms[1] automatically adjust revenue to address external cost pressures *independent of utility's own cost*
  - Statistical benchmarking studies gauging utility performance may indicate appropriate initial rates for the MRP or stretch factors[2]
  - Performance incentive mechanisms can drive improvements in particular areas of interest as it relates to affordability
- PBRs must be carefully designed to motivate strong performance and share benefits fairly with customers
  - Mechanisms are complex; regulator may need consultants
- Many states currently use MRPs for electric utilities[3]
  - CA, FL, GA, HI, LA, MA, NC, NH, NY, OR, SD, VT, WA[4]

Average annual changes (%) in electricity bills for Alberta residential customers (2008-2021)

Utility	COS (2008-2012)	PBR 1 (2013-2017)	PBR2 (2018-2021)
ATCO Electric	13.5	5.2	5.5
EPCOR	17.3	3.9	6.9
Fortis	15.8	4.1	5.5
Average	**15.5**	**4.4**	**6.0**

Source: Alberta Utilities Commission Decision 26356-D01-2021, adapted for LBNL by Commission consultant Pacific Economics Group Research (PEGR)

Average % change was calculated on typical residential bills as of January 1 each year, using information provided by the utilities in response to Commission information requests. Excludes energy commodity prices.

Examples:
- Average productivity growth of 3 Alberta distributors increased from -2.3%/yr under biennial rate cases (2007-2012) to -0.7%/yr under 2 rounds of PBR (2013-2023); O&M productivity increased from -0.7%/yr to 2.8%/yr
- >$315M productivity savings for first three years of Hydro One (Ontario) 2018-2022 MRP, exceeding forecasts

[1] Methods to design ARMs include forecasts and indexation to business conditions (e.g., inflation, customer growth)
[2] Included in ARM to reflect customers' share of expected benefits of cost containment from an approved MRP
[3] Source: PEGR
[4] So-called MRPs in DC, IL, and MD are actually CoS formula rates due to reconciliation mechanisms that cause a utility's revenue to closely track its own CoS. This may be accomplished with an earnings true-up mechanism that adjusts rates automatically to eliminate variances between a company's actual and target ROE.

Medium term

Improve methods for cost-effectiveness evaluation

Planning and Analysis

- Apply principles to justify spending considering rate impacts: (1) transparent, consistent methods; (2) credible assumptions and values based on sound data; and (3) holistic analysis of all benefits and costs
- Conduct initial cost-effectiveness (c/e) screening using one of the following methods, based on investment driver
  - **Lowest reasonable cost** – What is the lowest reasonable cost to meet a *safety, reliability, or other statutory/regulatory requirement*?
  - **Benefit-cost analysis** (*drivers not listed above*) – Do benefits outweigh costs for a specific expenditure or interrelated expenditures?
- Prioritize expenditures – Assess each proposed expenditure against each identified objective and metric
  - Apply a weighting factor to total numerical score based on the contribution of a proposed solution to addressing each objective
  - Rank each expenditure from highest to lowest priority using final score and cost for each solution
  - Value-spend efficiency method (e.g., Ameren integrated grid plan)
    - Assess each proposed project based on benefit per unit cost
    - Determine metrics for individual benefit or combination of benefits
    - Optimize spending across a portfolio of investments by cost category or budget
- Regulators can require utilities to fully describe proposed c/e methods for review in cost recovery applications, provide direction on acceptable methods, or standardize methods utilities may use for cost recovery

Example: Portland General Electric 2022 Distribution System Plan

	Score	Weighting	SAM score (avg)	
Reliability	4	27%	1.08	3.2
Risk	4	27%	1.08	
Financial	4	27%	1.08	
			Portfolio score (avg)	
Safety	0	4%	0	0.2
Compliance	0	4%	0	
Environmental	0	4%	0	
Operational	1	4%	.04	
Customer	1	4%	.16	
Final prioritization score; Optimizes on value			Total value 3.4	

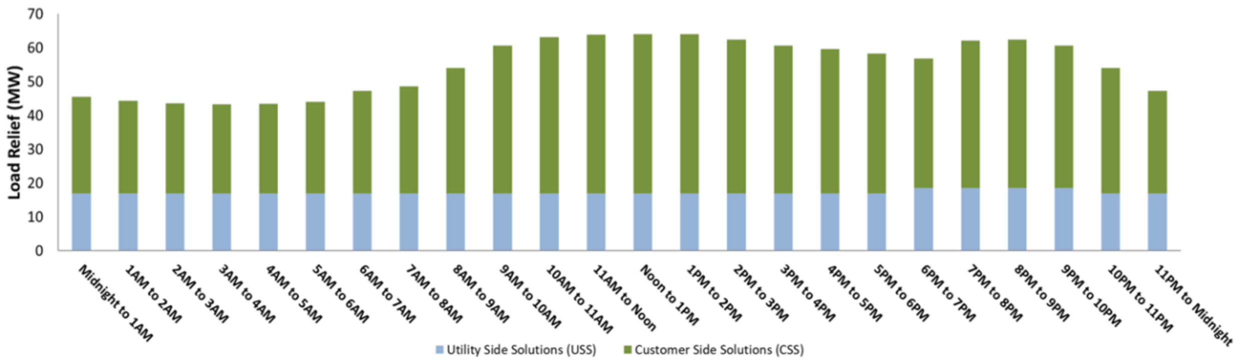
Medium term

Require alternatives analysis for distribution expansion

Planning and Analysis

- Regulators can require utilities to consider all options for distribution-system needs
  - Examples: IL and MD directed utilities to perform alternatives analysis in distribution system plans
  - To reduce planning costs, it is important to balance the number of alternatives considered with potential impacts of the analysis
- Includes alternatives to traditional assets—e.g., pole resilience ratings, various transformer technologies
- Non-wires alternatives (NWA) – Technologies or operating practices to reduce congestion and manage peak demand, offsetting need to make investments in conventional assets like substations and feeders
  - Examples include batteries, gas generators, microgrids, time-varying rates, conservation voltage reduction (CVR), Volt-VAR optimization (VVO), dynamic phase balancing, and geotargeted load management programs
  - Acquisition could be through procurements (solicitations), programs, and/or customer pricing
- Improved grid utilization – Increasing electricity consumption during off-peak hours can spread system costs across more sales, potentially reducing rates
  - Such as targeting load growth in areas of the grid that have capacity, developing grid utilization metrics and load shifting programs

Examples
- ConEd (NY) Brooklyn Queens Demand Management NWAs deferred two substations
- Ameren (IL) CVR/VVO reduced peak demand by 13 MW
- Dynamic phase balancing (here and here)



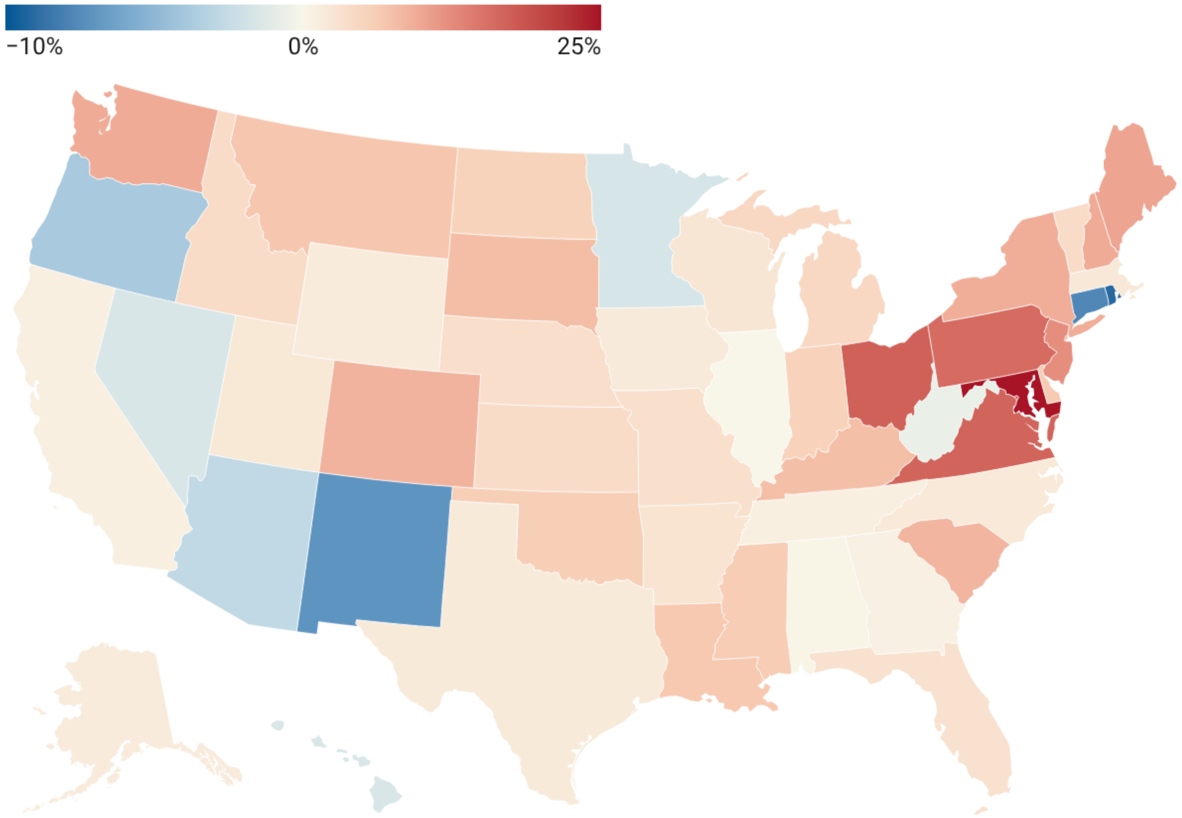
Source: Con Edison BQDM Report Q3 2025

The infection is spreading: retail prices are likely to outrun inflation in the near-term absent thoughtful regulatory and policy intervention

Retail price increases <u>over the last year</u> outpaced inflation nationally and in a growing number of states

Percentage Change in All-Sector Retail Electricity Prices: Jan-Mar 2025 to Jan-Mar 2026

Percentage change, adjusted for inflation in 2025$



Source: EIA • Created with Datawrapper

This Overall Project Currently Includes Multiple Products

Annual and periodic data updates

Compiles and synthesizes data as it becomes available, including this update

Data visualization tools

Allows users to explore some of the data compiled under this research effort

Peer-reviewed journal article

Highlights a subset of the trends through 2024, with a focus on statistical analysis of broad drivers

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

For More Information

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Acknowledgment

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