
Source: DALL-E

LAWRENCE BERKELEY NATIONAL LAB

Housekeeping Notes for Webinar Attendees

- This webinar is being recorded, will be posted publicly within a week.
- You will be muted during the entire webinar.
- Please use the Q&A function within Zoom to ask questions.
- We will try to respond to Q&A during the presentation and hope to have ~10 minutes to respond verbally at the end of the webinar.
- For the full study: https://emp.lbl.gov/publications/electric-utility-distribution-costs

Electric Utility Distribution Costs

Scoping study on trends, drivers, and possible response strategies

Ryan Wiser, Galen Barbose, Peter Cappers, Will Gorman, Sean Murphy, Lisa Schwartz, Natalie Mims Frick, Guillermo Pereira, Arthur Mallet Dias, Jessalyn Chuang, and Vinita Srinivasan

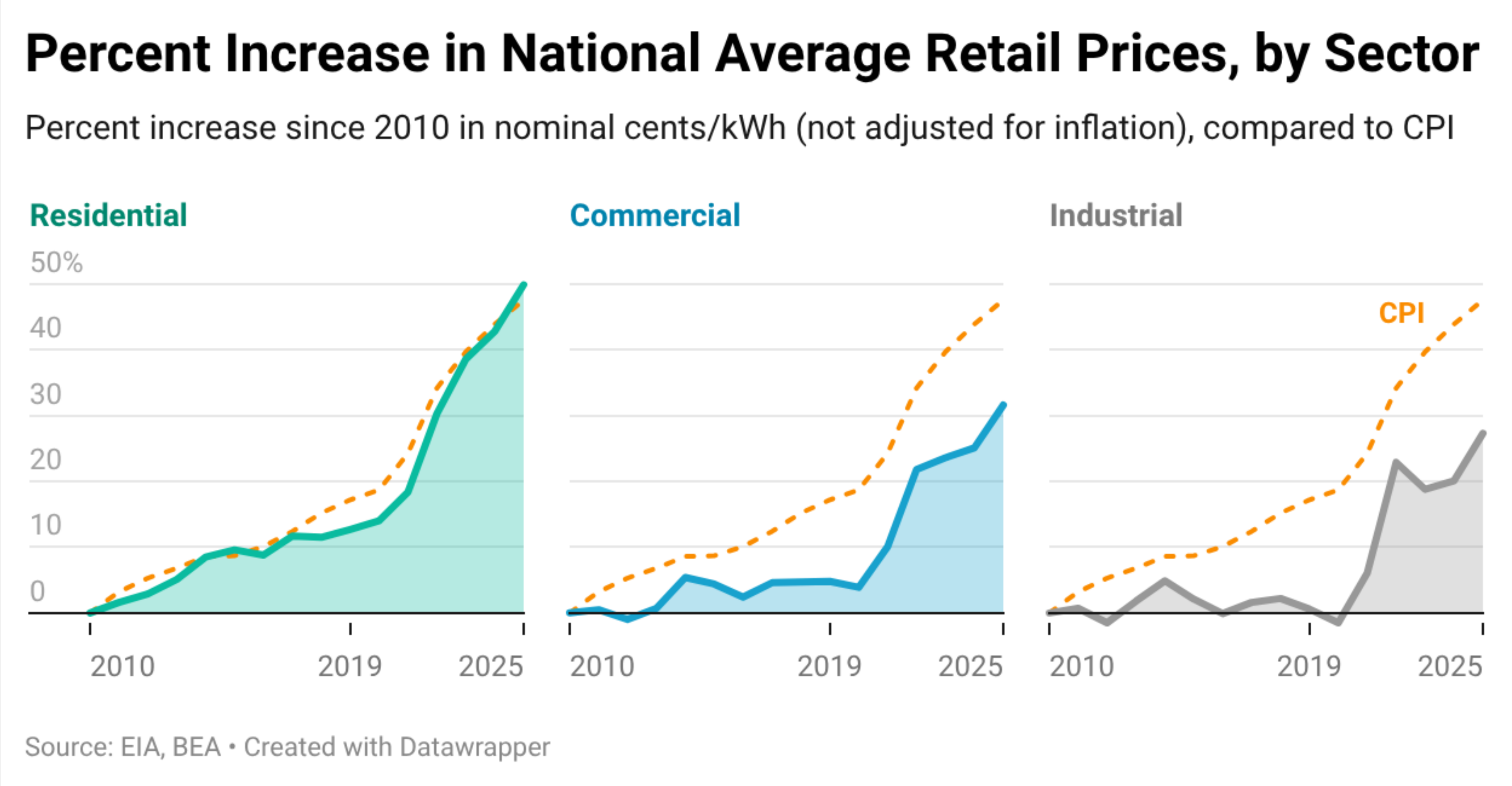
Lawrence Berkeley National Laboratory

May 2026

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

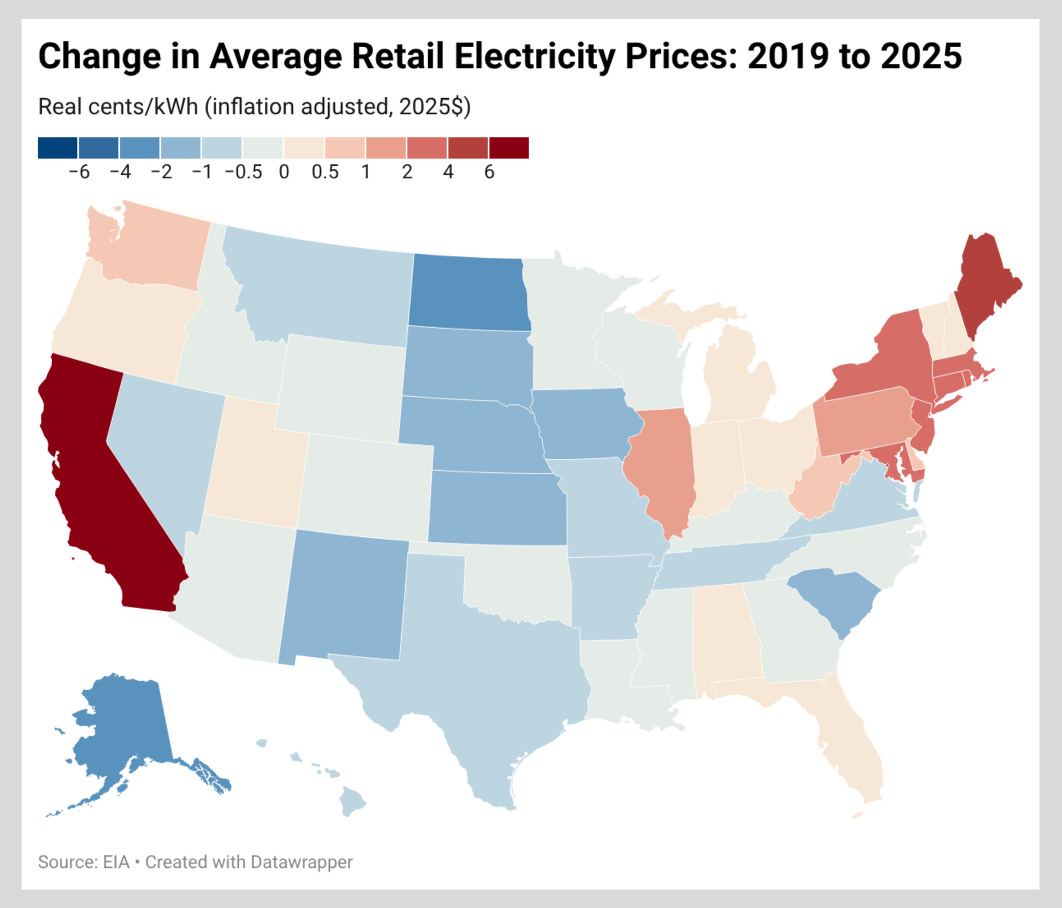
Nominal retail electricity prices have spiked in recent years, motivating our research to understand price trends and drivers

- In nominal terms, average prices increased **29%** from 2019 to 2025 and **39%** since 2010; adjusting for inflation, real prices were **3%** higher than in 2019 and **6%** lower than in 2010
- Residential prices increased more rapidly than C&I
- C&I increases were lower than the CPI; residential price increases higher
- From 2024 to 2025, all-sector average prices increased 5.3%, 2x the CPI

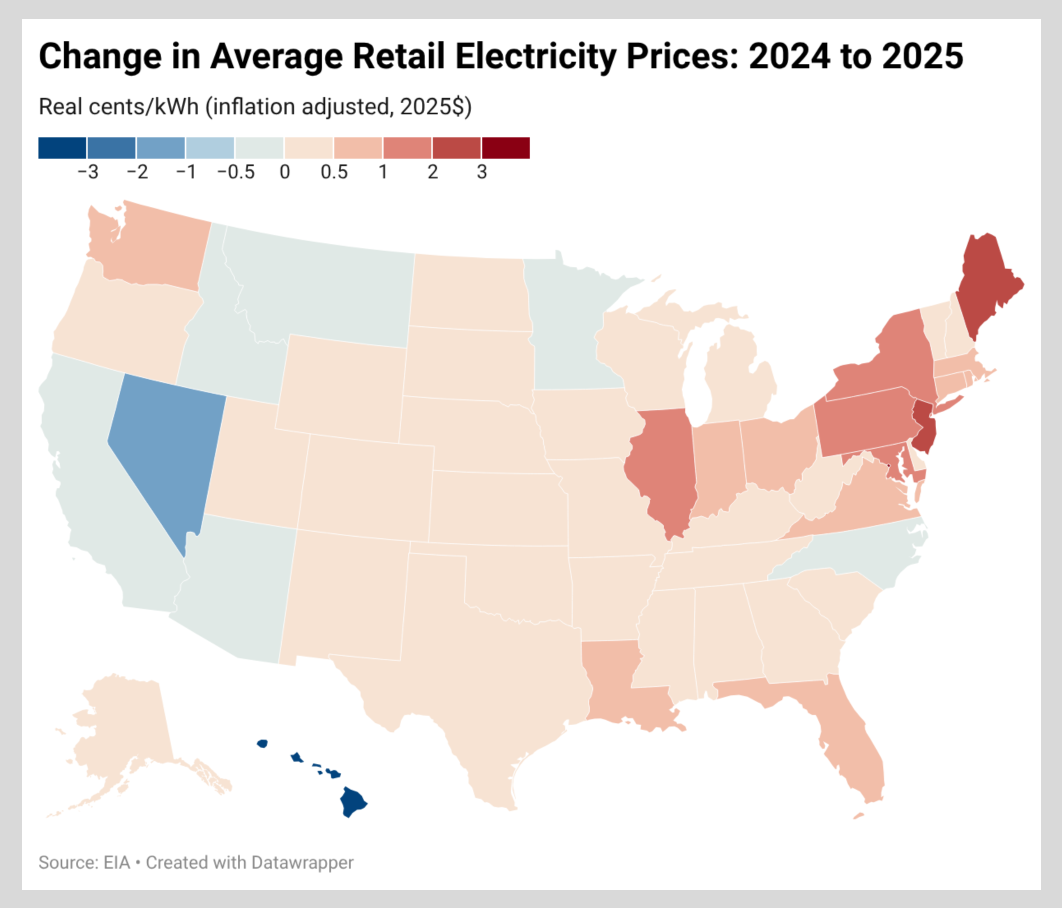


These trends vary dramatically across states, highlighting need for regional analysis that unpacks key drivers of differences

2019-2025: 29 states with inflation-adjusted decreases; largest increases in California, Northeast, some states in Mid-Atlantic, West, Great Lakes

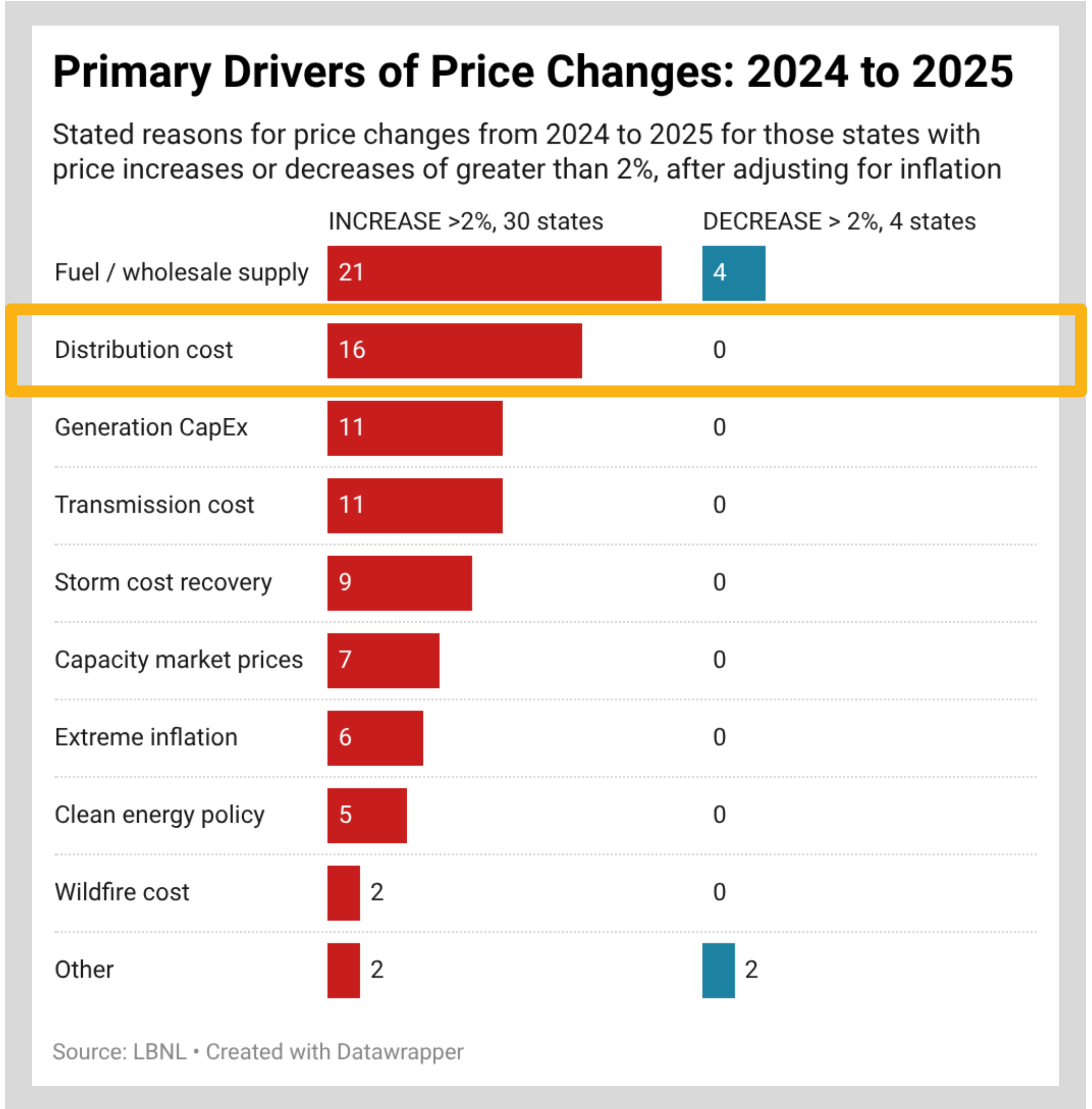


2024-2025: 43 states/DC with increases; largest increases in Northeast, Mid-Atlantic, Great Lakes, some in Southeast and West



Distribution system costs are a primary YoY driver of recent retail price changes across the country *(and a key driver of longer-term increases)*

- Figure summarizes our assessment of primary price drivers from 2024 to 2025 for states with **increases (red)** or **decreases (blue)**
- Focused on states with larger inflation-adjusted price increases (>2%, 30 states) or decreases (>2%, 4 states)
- Reviewed filings, rate cases, tariffs, news, press releases, other analyses to broadly assess the primary drivers for year-over-year (YoY) all-sector average price changes



Scoping Study on Distribution Costs: Research Objective and Contents

Objective: Quickly synthesize information that will help stakeholders understand the scope, scale, and drivers of recent increases in electric-utility distribution expenditures, while beginning to arm regulators and policymakers with potential response strategies.

FIVE CORE SECTIONS

- Trends in past and recent investor-owned utility (IOU) distribution costs
- Characterization and drivers of planned IOU distribution expenditures
- IOU rate increase and equity return requests and approvals
- IOU regulation and potential incentive misalignment
- Regulatory options to manage distribution-related rate increases

Notes: Intends to be a scoping-level assessment. The analysis focuses on investor-owned utilities (IOUs), and some sections address issues that extend beyond distribution: **see next slide**.

Research Scope

Goal: Focus on **IOU** distribution-related **infrastructure costs**. However, several sections address issues that are **not exclusive to distribution.**

Why Focus on IOUs (not also publicly owned utilities, POUs)?

- **Dominate sales:** ~70% of all retail electricity sales in the U.S. are served by an IOU distribution system
- **Price increases:** From 2019-2024, average IOU prices were up 2% (in real $); POU prices were down 8.7%
- **Data availability:** Data on distribution costs and rate increase requests are more readily available for IOUs
- **Policy salience**: IOUs are regulated by small # of PUCs, POUs are overseen by many independent boards *[note, however, that some of the "planning and analysis" options discussed in section 5 could apply to POUs]*

Where and Why Cover Topics Beyond Distribution?

- **Sections 1 & 2:** focus on distribution infrastructure costs (Section 1 also has one slide on business operations)
- **Section 3:** data availability required a focus on IOU rate requests that are not exclusive to distribution; however, IOU spending on distribution has outpaced spending on generation, transmission and business operations, so Section 3 should broadly reflect distribution-related trends
- **Section 4:** emphasizes issues related to utility regulation that cannot be separated by industry segment (e.g., distribution vs. generation or transmission); where possible, we provide distribution-related examples
- **Section 5:** highlights regulatory options, some of which are somewhat exclusive to distribution (e.g., distribution planning & asset management) but most options properly also could apply to generation & transmission

Section 1:
Trends in Investor-Owned Utility Distribution Spending and Costs

Objective, Data and Methods

Objective

EEI estimates that 31%[1] of all electric IOU capital spending since 2015 has been for distribution equipment. The objective of this section is to disaggregate IOU distribution spending trends further by region and cost category, including O&M, and to estimate the approximate rate and bill impacts, considering how CapEx is recovered in rates.

[1] EEI (2025)

Data and Methods

- **Data**
  - **FERC Form 1 data through 2024**
  - Expenses reported for distribution system, consisting of CapEx and O&M, each broken out further into more granular categories on separate schedules
  - Accounting costs from Income Statement, consisting of O&M, depreciation, taxes, interest, and net income; used to estimate distribution-related rate impacts
  - **Non-infrastructure related costs** (e.g., business operations, insurance, billing) that utilities and regulators may allocate to distribution services **are generally excluded** from the analysis, but are presented on the last slide for reference
- **Methods**
  - All values inflation-adjusted to real 2025$, using national CPI
  - Focus primarily on 2014-2024, emphasizing more-recent years where possible
  - Trends presented for the U.S. as a whole and for 9 regions (7 ISO/RTOs + the non-ISO portions of the Southeast and West)
  - **Rate and bill impacts of distribution service approximated** by allocating costs to distribution service and applying a 3-year rolling average
  - Rate estimates are averages across all customer classes, but residential and commercial customers are generally allocated more of these costs

Limitations and Caveats

- IOUs are the only distribution companies that file FERC Form 1

Percent of 2024 Distribution Service Sales by FERC Form 1 Filers

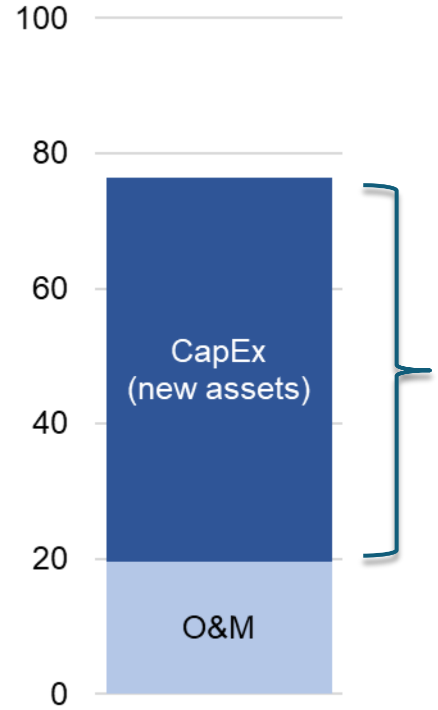
CAISO	ERCOT	ISO-NE	MISO	NYISO	PJM	Southeast (non-ISO)	SPP	West (non-ISO)	**Total U.S.**
89%	69%	87%	73%	81%	86%	58%	49%	52%	**69%**

- Regional comparisons are imperfect
- The timeframe of comparison matters
- "Rate impacts" presented here are rough proxies
- Some variation may exist in how utilities report data
- Focus of this section is on identifying descriptive trends at the national and regional levels

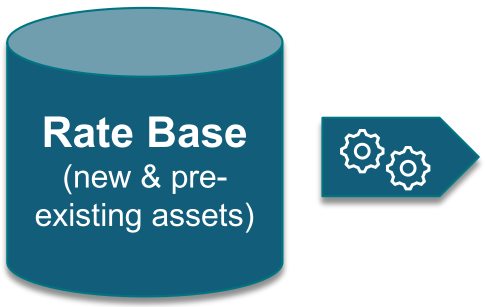
Key Terminology and Concepts: "Spending" vs. "Costs"

We present FERC Form 1 data for both annual expenditures (aka "spending") as well as accounting costs, where the latter are then used to estimate rate impacts

Distr. Spending
(billion 2025$)

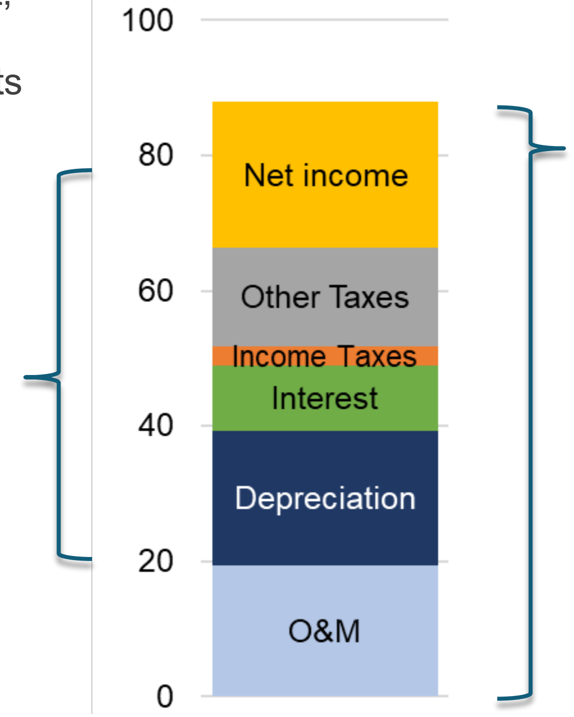


- Utilities add CapEx for new assets to their rate base
- Depreciation, interest on debt, net income, and taxes are based on all rate-based assets
- Net income can also be earned through O&M savings



- O&M is *not* part of the rate base; spending = costs

Distribution Costs
(billion 2025$)



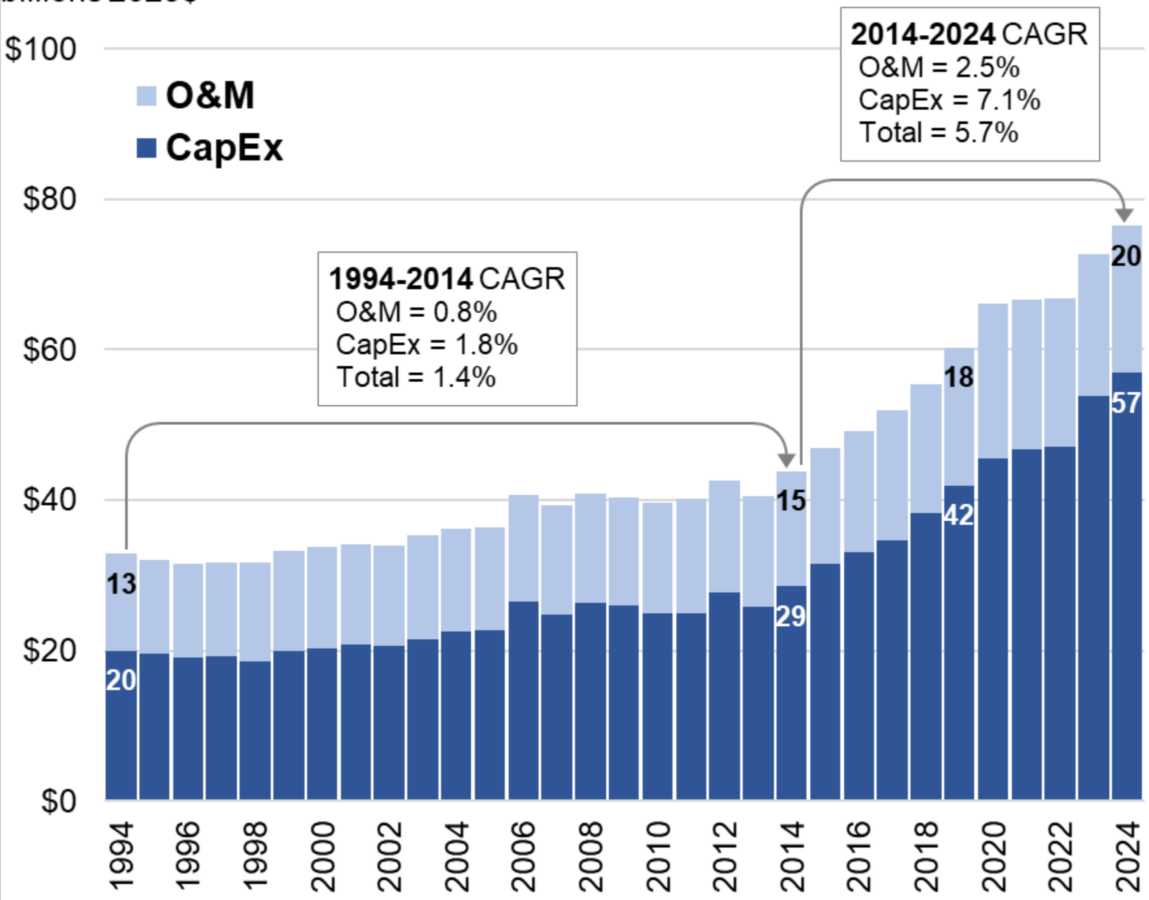
$$\textbf{Rate Impact} = \frac{\text{Distribution Costs}}{\text{Retail Sales}}$$

- Depreciation costs for distribution assets are reported directly on FERC Form 1
- Interest, income, and taxes are instead reported across all utility functions
- We allocate a portion of those costs to distribution services based on its share of either total utility deprecation costs or the net book value of all utility assets (noting again that this differs from the more complex process utilities use to functionalize costs in rate cases)
- We then add O&M, and estimate all-sector average rate impacts by dividing all distribution-related costs by retail sales across all customer classes

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

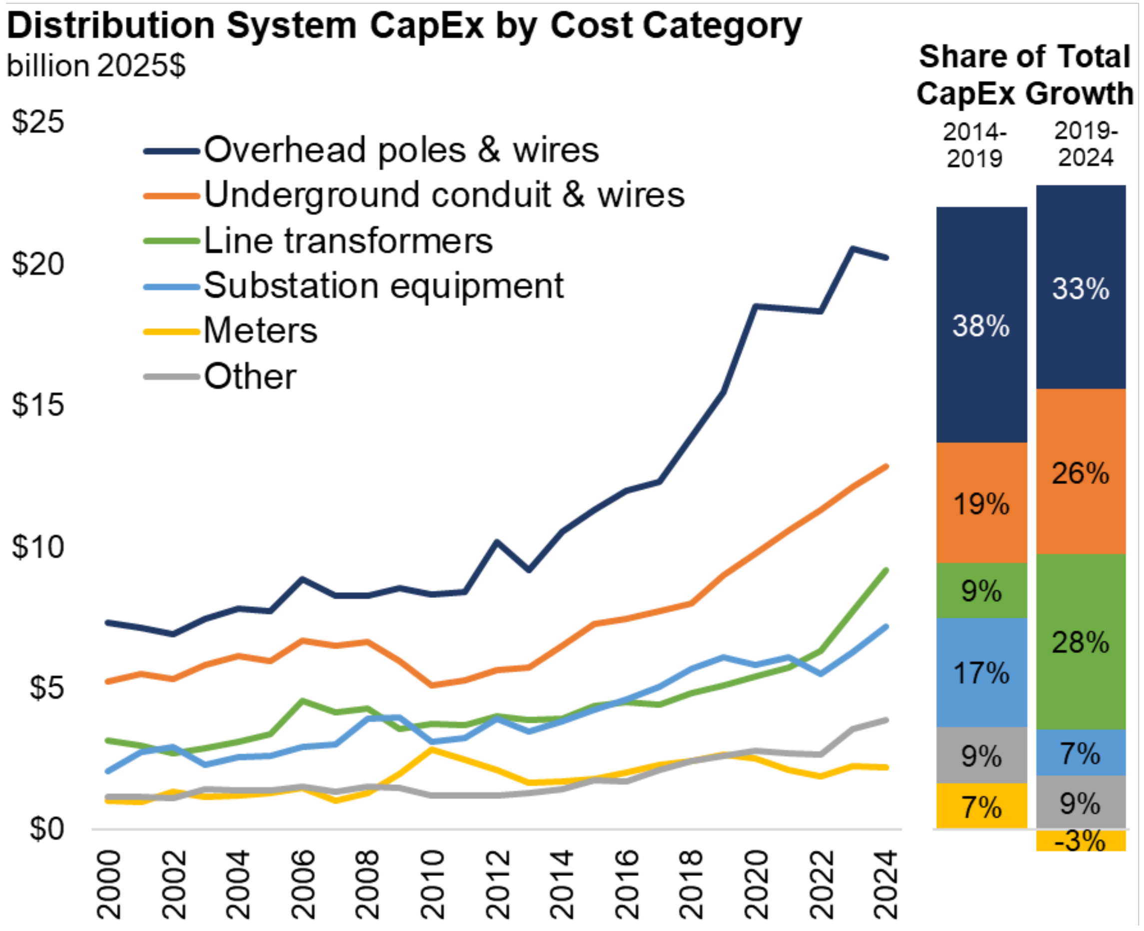
Annual U.S. Electric IOU Distribution Expenditures
billions 2025$



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.

Distribution CapEx has been growing across most major cost categories, with no single dominant driver; O&M growth is mostly for overhead lines

- With the exception of meters, CapEx on all other major distribution infrastructure costs has been growing over the past decade-plus
- CapEx on overhead poles & wires, along with underground conduit & wires, began to rise sharply in 2014, and is the source of the “inflection point” in total distribution spending noted previously
- CapEx on line transformers has accelerated more recently and, accordingly, become a much more significant contributor to overall CapEx growth in recent years
- O&M cost growth consists almost entirely (~90%) of maintenance costs for overhead lines, almost half in CAISO (not shown here)



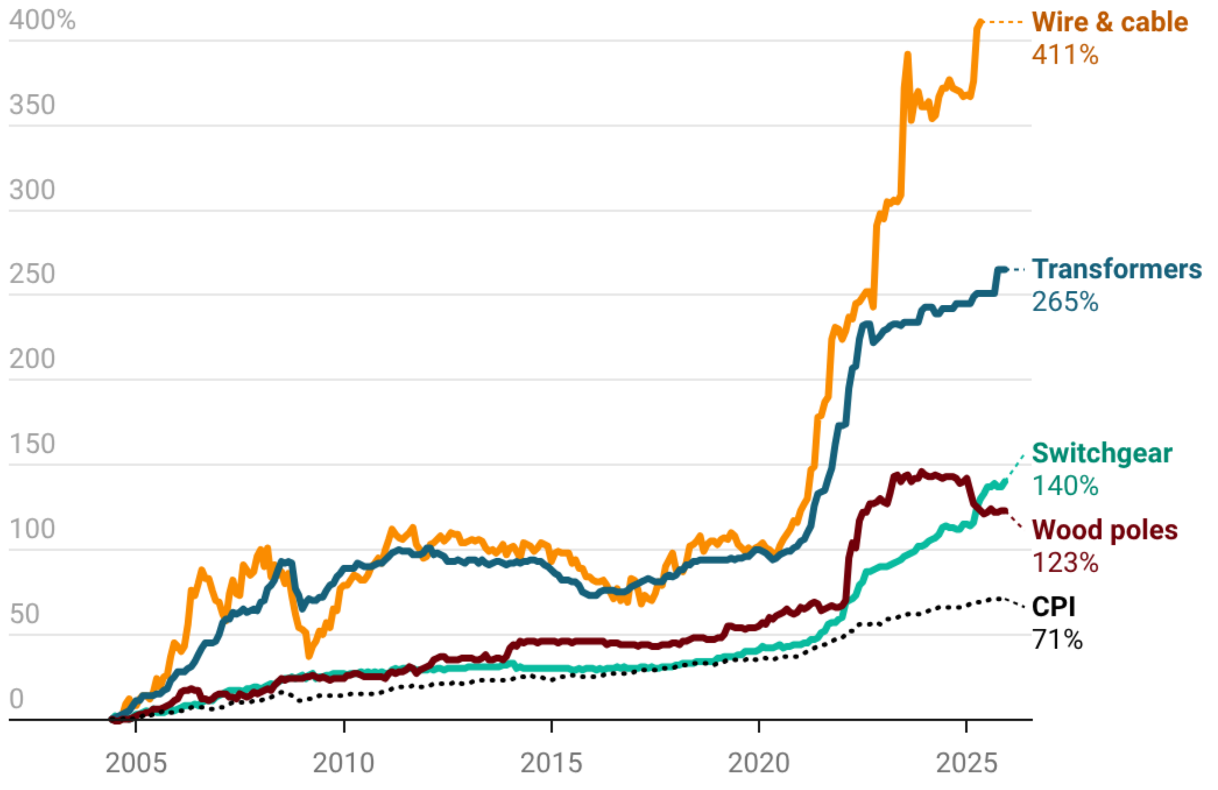
Notes: The six cost categories shown here are consolidated from the 15 categories used for distribution plant in service, with six of those combined under “Other”. In the stacked bar charts on the right, the percentage contributions add to 100%, including any negative values.

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



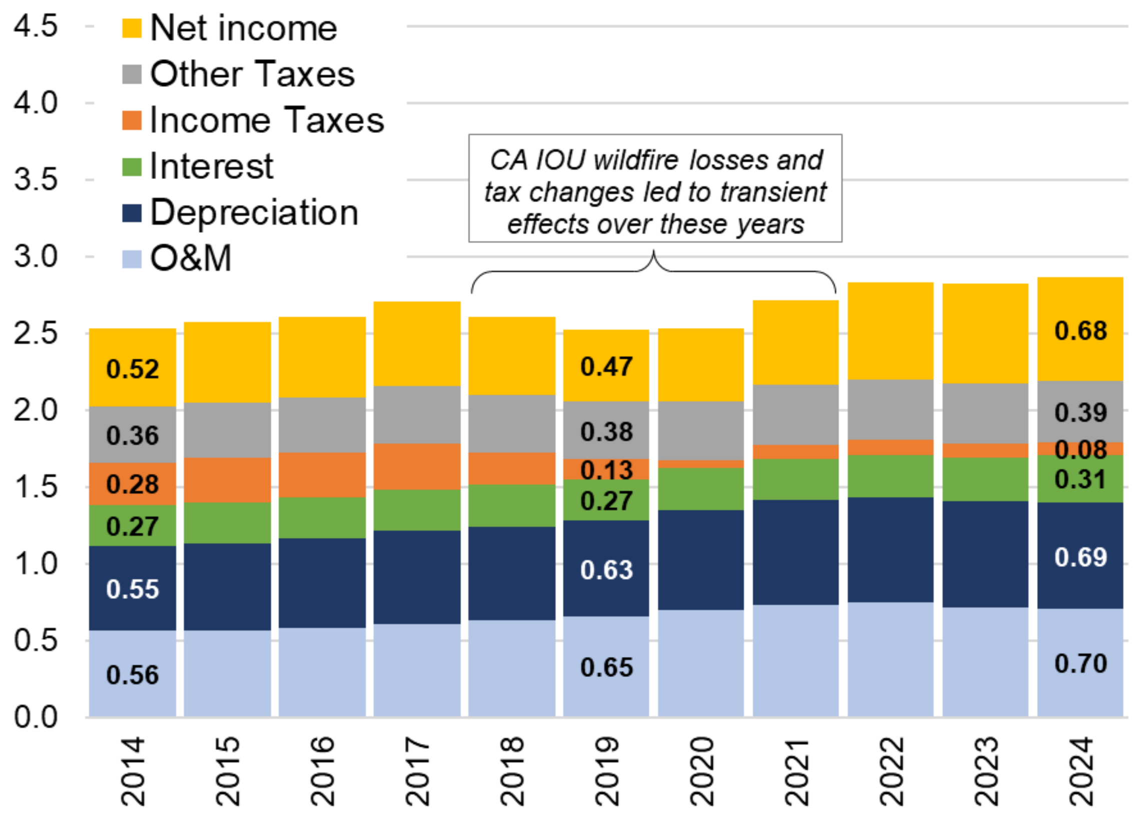
Source: BLS, FRED • Created with Datawrapper

[1] EEI (2025)

Average IOU distribution costs rose by 0.33 ¢/kWh since 2014, in inflation adjusted terms, representing 32%* of the overall rise in U.S. avg. IOU rates

- The rate impact of CapEx is spread out over time via depreciation and interest costs plus a portion of net income and taxes (though the latter two can fluctuate for other reasons)
- **Nationally, distribution CapEx has played a larger role than O&M** in driving up rates
  - Since 2014, depreciation + interest costs grew 0.18 ¢/kWh compared to 0.14¢ for O&M costs; regional results vary as shown later
  - However, the two grew similarly from 2014-2019; it is only since 2019 that CapEx-related costs became a more-dominant driver (0.11 cent increase vs. 0.05 cents for O&M)
- Distribution-allocated **net income is up by ~0.16 ¢/kWh**, in part due to CapEx growth

IOU Costs Allocated to Distribution: Proxy for Rate Impacts
cents/kWh (2025$, rolling 3-year average)



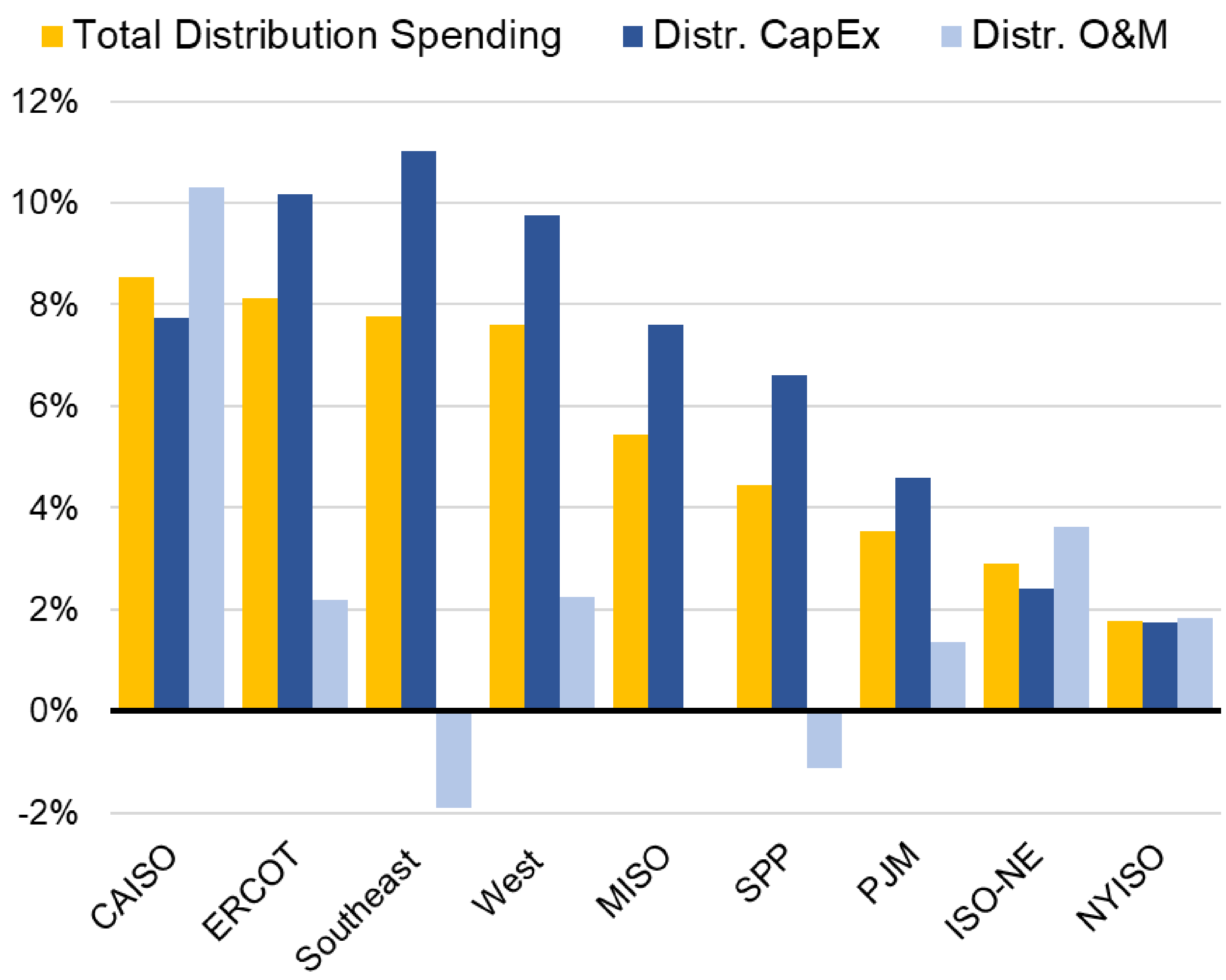
* This 32% number is calculated based on nominal values. Average IOU rates in real 2025$ *declined* by 0.5 cents/kWh from 2014-2024; rising distribution costs, in effect, reduced the size of that decline. Comparisons of accounting costs to average IOU rates over more recent timeframes are less meaningful, due to fluctuations in income taxes and net income that occurred over the years following the 2017 reduction in corporate tax rates, which were then followed by the pandemic years.

Notes: Based on data reported on FERC Form 1 "Statement of Income" schedule, divided by total bundled plus delivery-only IOU sales. Income Taxes (lines 15-19), Other Taxes (line 14), Interest (line 70), and Net income (line 78) are reported across all electric utility functions and, for Interest and Net Income, include costs for non-electric operations. Values shown here are based on allocations to distribution services. Depending on the line item, allocations are based on depreciation expenses, the book value of plant in service, or net utility operating income. Net income excludes income from non-utility operations.

Distribution system spending has been increasing everywhere, though at widely varying rates, with CapEx usually the primary driver

- The **highest overall growth (~8% per year) has been in CAISO, ERCOT, and the non-ISO Southeast and West**
- As with the national trends, IOU spending growth at the regional level was **primarily CapEx-driven**, though **CAISO saw 10% annual growth in O&M** (most of that concentrated over the 2017-2020 period), and ISO-NE also saw relatively high O&M growth
- Prior work has attributed a sizeable share of recent spending growth and associated rate increases to wildfire mitigation (in CAISO, especially, and elsewhere in the West) and to storm recovery (in Gulf & east coast states)

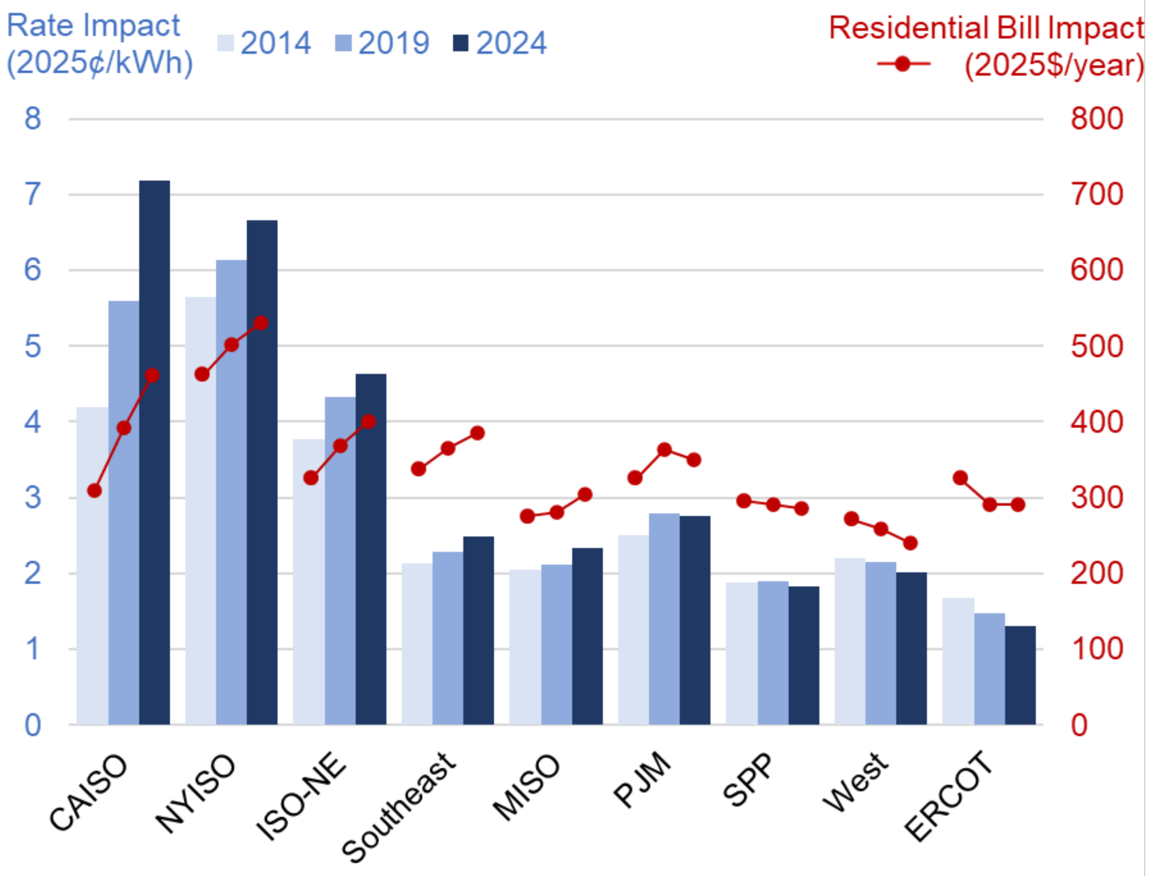
2014-2024 Compound Annual Growth Rates (CAGR)



The all-sector average rate impacts of increased distribution spending vary across regions—in some cases diverging from spending trends

- FERC Form 1 distribution costs correspond to **all-sector average 2024 IOU rate impacts of ~1.3-7.2 ¢/kWh**, depending on the region
- Differences across regions in terms of residential *bill* impacts are less pronounced due to different levels of per-customer sales, and range from ~$250-500/yr in 2024
- **CAISO, NYISO & ISO-NE had the highest all-sector average impacts and saw the largest rise over the past decade (~3¢ in CAISO and 1¢ in the other regions);** NYISO and ISO-NE had slow growth in distribution expenditures, but rising rate impacts due to contracting load and either increasing state taxes and/or O&M
- Rate impacts grew by 0.3-0.4¢ in SE, MISO & PJM; or declined, including in ERCOT and non-ISO West, which had robust spending growth

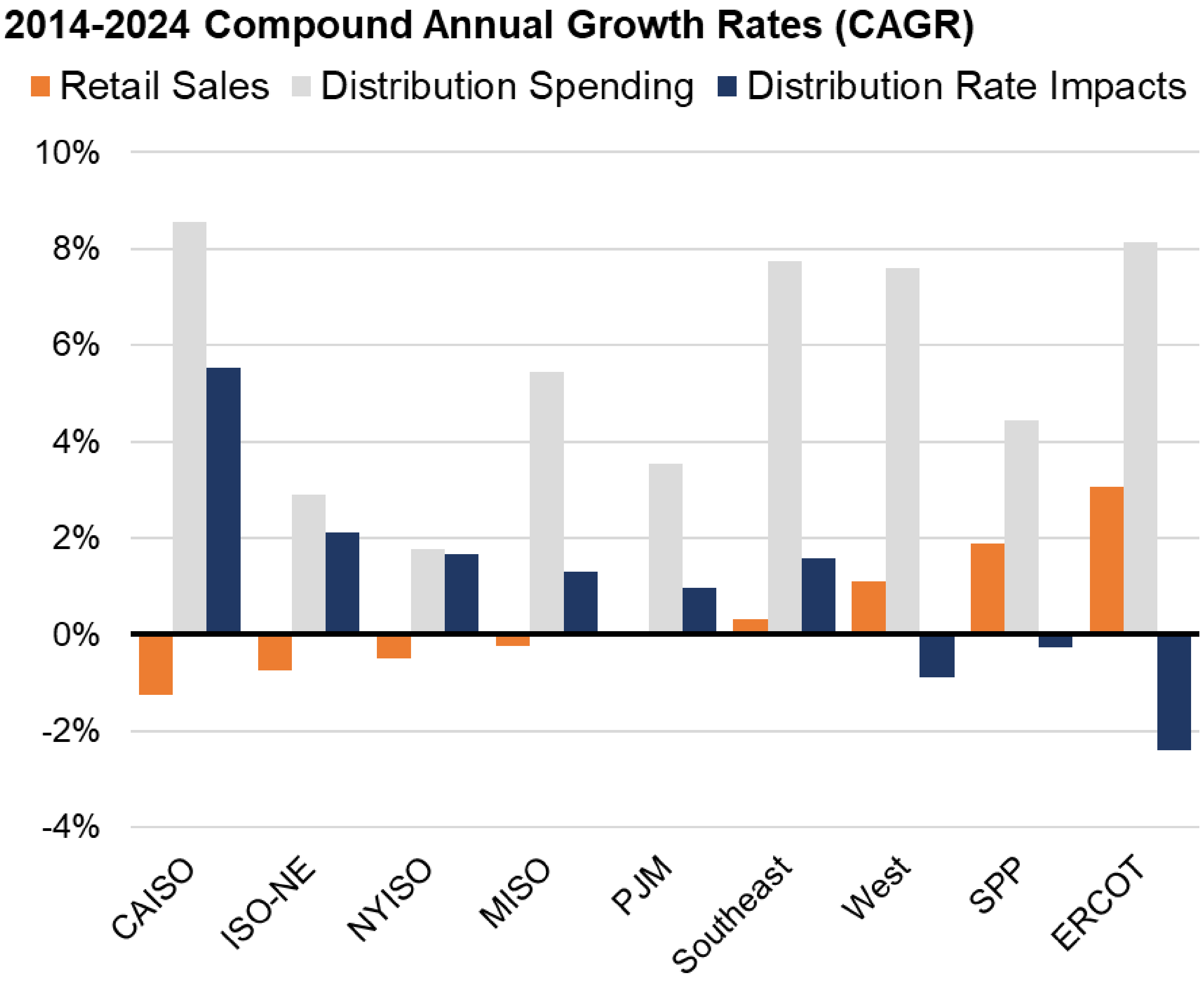
Approximate Rate and Bill Impacts of Distribution Costs



Notes: All values are 3-year rolling averages. See earlier figure with national rate impacts for details on how rate impacts are derived. Residential bill impacts estimated by multiplying the rate impact by average residential electricity consumption in each region and adjusting, based on EIA data, by the ratio of average residential rates to average rates for all customers. For CAISO, 2019 values are the midpoint between the rolling averages for 2017 and 2022, as the values for intervening years were significantly depressed by PG&E's wildfire-related losses.

Load growth has helped to mute the effects of spending growth in some regions, while load contraction has magnified rate impacts in others

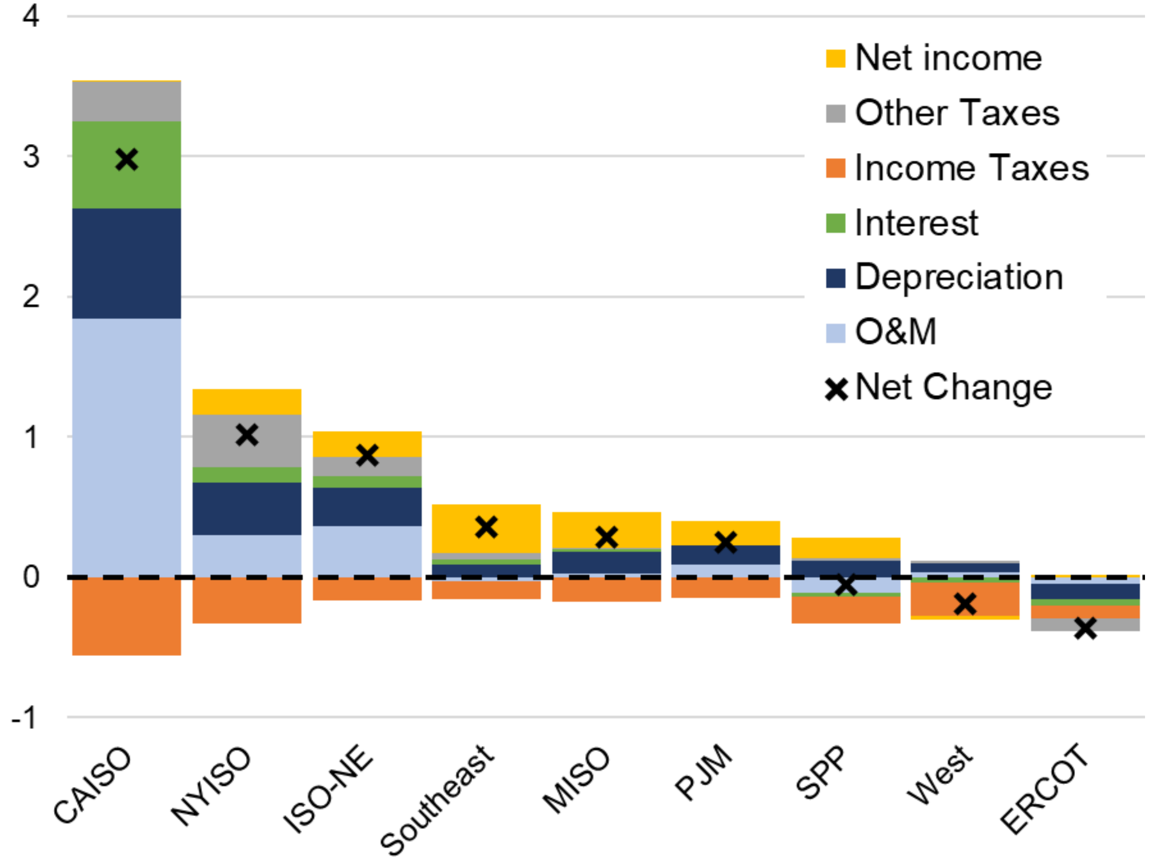
- Load growth can be both a driver for additional distribution spending, as well as a means of muting the average rate impact by spreading spending over a larger sales base
- Over the 2014-2024 period, those regions with the highest retail sales growth (ERCOT, SPP, and the non-ISO West) saw declining rate impacts from distribution spending—despite relatively high spending growth
- Conversely, regions with declining retail sales (partly related to net metering) saw rate impacts rise the most, despite in some cases relatively low growth in distribution spending



O&M cost growth constituted 60% of the distribution-related rate increase in CAISO and 30-40% in ISO-NE and NYISO, but negligible elsewhere

- Increases in **O&M rate impacts** over time (under our methodology) are based on the difference between O&M cost growth and retail sales growth, and are therefore greatest in regions with higher O&M growth (CAISO & ISO-NE) or lower sales growth (same two + NYISO)
- Increases in **depreciation impacts** depend in part on how the depreciation schedule of new CapEx compares to existing assets: e.g., NYISO had much less CapEx growth than the SE, but rate impacts were more than twice as large because of differences in depreciation; differences between CAISO & ERCOT are also in part driven by depreciation assumptions
- Differences in depreciation assumptions may be due to the type of assets being added <u>**or**</u> differing regulatory practices

2014-2024 Change in IOU Distribution Rate Impacts
cents/kWh (real 2025$, rolling 3-year averages)

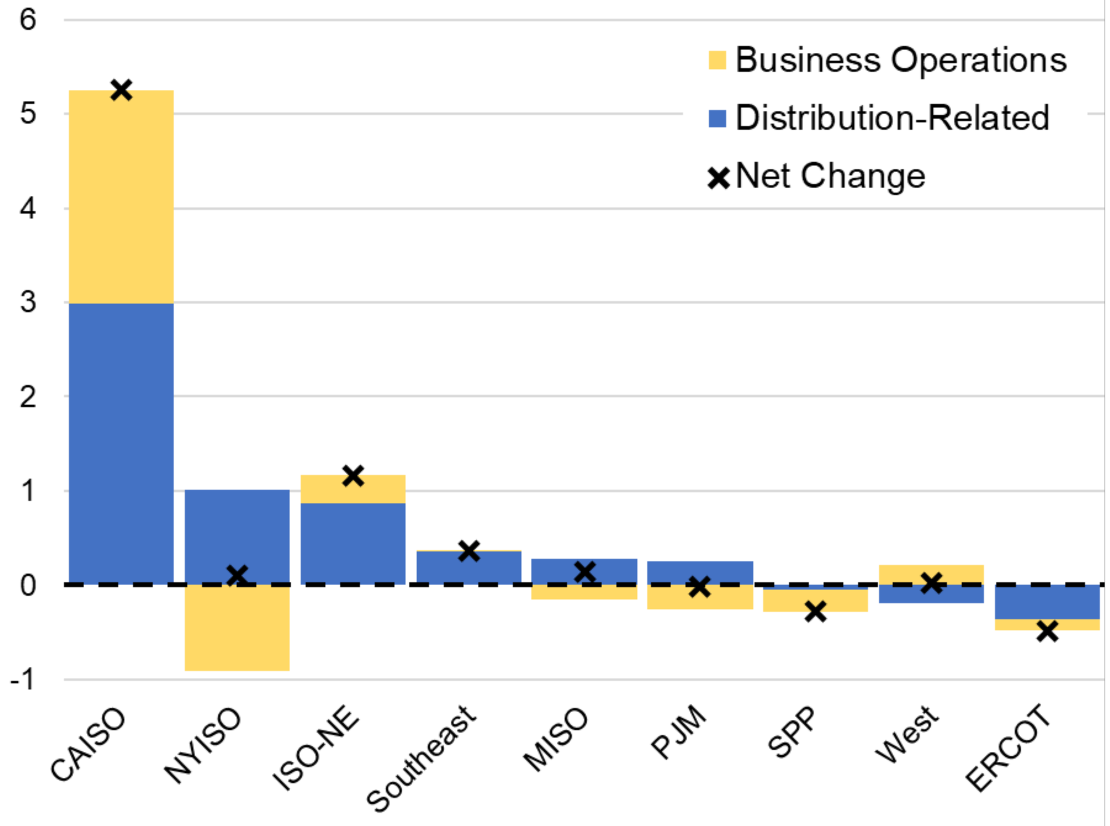


Notes: Values shown here are based on the difference between the 3-year rolling averages for 2024 and 2014 (i.e., between the 2022-2024 average and the 2012-2014 average). See figure with national rate impacts for additional details on how FERC Form 1 costs are allocated to distribution service.

Business operations costs rose dramatically in CAISO due to wildfire costs, but generally had smaller and/or offsetting impacts in other regions

- The FERC Form 1 O&M expense schedule includes a variety of "business operations" related costs, which utilities may sometimes allocate to distribution service
- These are not included in earlier figures, but are shown here for reference, as a change in estimated all-sector average rate impact over 2014-24, compared to the distribution-related impacts shown previously
- In CAISO, the estimated rate impacts of these business operations costs rose, on an inflation adjusted basis, by 2.3 ¢/kWh, consisting mostly of wildfire-related expenses, adding substantially to the 3.0 ¢/kWh rise in distribution-related rate impacts
- Changes in business operations costs in other regions were considerably smaller and often negative—most notably in NYISO where the estimated rate impacts fell by 0.9 ¢/kWh, due mostly to reductions in the cost of funding "employee pension and benefits" and largely offsetting the rise in direct distribution costs

2014-2024 Change in Distribution & Business-Ops Rate Impacts
cents/kWh (real 2025$, rolling 3-year averages)



Notes: Business operations rate impacts are based on the summation of costs across several O&M expense categories reported on FERC Form 1, including Customer Accounts, Customer Service and Informational, Sales, and General and Administrative, each including multiple distinct line items. They also include a number of line items from the Income Statement not otherwise included in earlier figures, the most significant being Regulatory Debits and Credits.

Section 2:
Characterization and Drivers of Planned Distribution Expenditures

Key findings summary

1. Many utilities are planning for significantly increased distribution spending through 2030; among a sample of 22 utilities, 14 have planned CapEx spending growth above the rate of inflation

2. For 20 out of 22 utilities sampled, planned spending on managing the existing distribution system exceeds planned spending on capacity expansion for load growth and DER integration

3. Asset replacement, safety and reliability, and resilience are all drivers of CapEx for managing the existing system; for capacity expansion, load growth is the dominant driver (not DER)

Section 3:
Utility Rate Increase and Equity Return Requests and Approvals

Objective, Data, and Methods

Objective

State regulators review investor-owned utility (IOU) rate change and return on equity requests, approving them in full, denying them in full, or approving them in part. We highlight national and regional trends in IOU request levels (revenue requirements and return on equity) as well as the share of IOU requests approved by regulators and how those shares have changed over time.

Data and Methods

- **Data**
  - IOU revenue requirement (“rate”) and ROE/WACC requests and approvals: S&P Global
  - Covers vast majority of IOU sales (148 largest IOUs are in S&P Global sample; covers all states except Nebraska, which doesn’t have an IOU)
- **Methods**
  - Summarize raw data as well as approval percentages (i.e., percentage of requests that were ultimately authorized)
  - Rate increase approval percentages are weighted by request amounts
  - Report data nationally and, in some cases, regionally (using the same regionalization methods as established in Section 1)

Limitations and Caveats

Data limitations

- S&P Global includes all revenue requirement change requests, not limited to distribution expenditure
- S&P Global includes all cases that would result in a change of at least $5M in revenue requirements, inclusive of some rider cases; however, limited-term fuel adjustment costs and storm recovery costs are not captured

Caveats in interpretation of S&P Global data

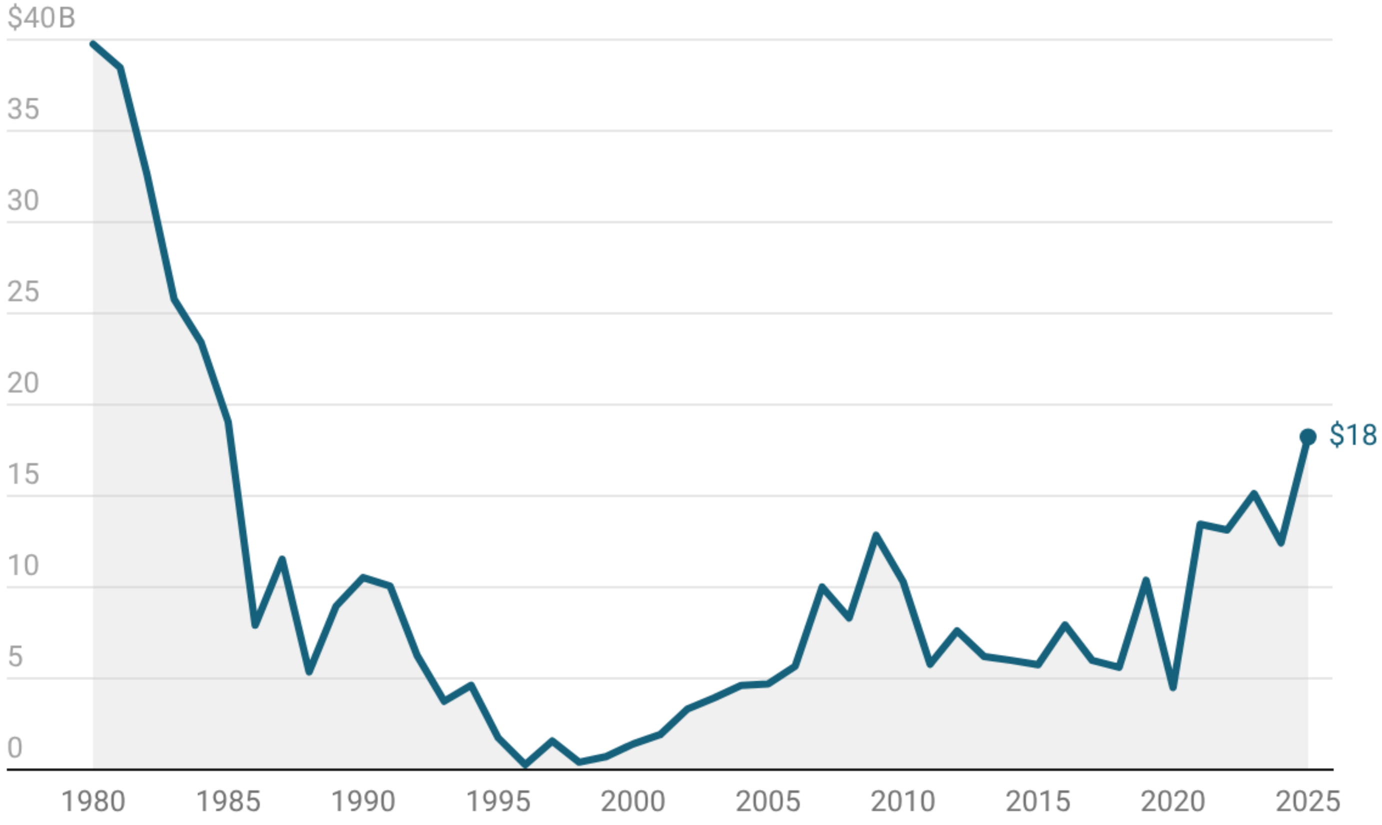
- For multi-year rate change requests, S&P Global sums the requests and reports one aggregate amount for the year of rate case
- Comparing data before and after the 1990s is complicated by restructuring and generation divestiture; to focus attention on a more-recent timeframe, most graphics include data from 2001 to 2025
- Higher approval percentages for rate increases and ROE requests could imply, e.g.: more-defensible utility rate increase and ROE requests; lower-levels of scrutiny on utility requests; other changes in the overall operating, regulatory, and legislative environment; or other factors – we do not opine on these drivers

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

Investor-Owned Utility Rate Change Requests

Billion 2025$



Source: S&P Global • Created with Datawrapper

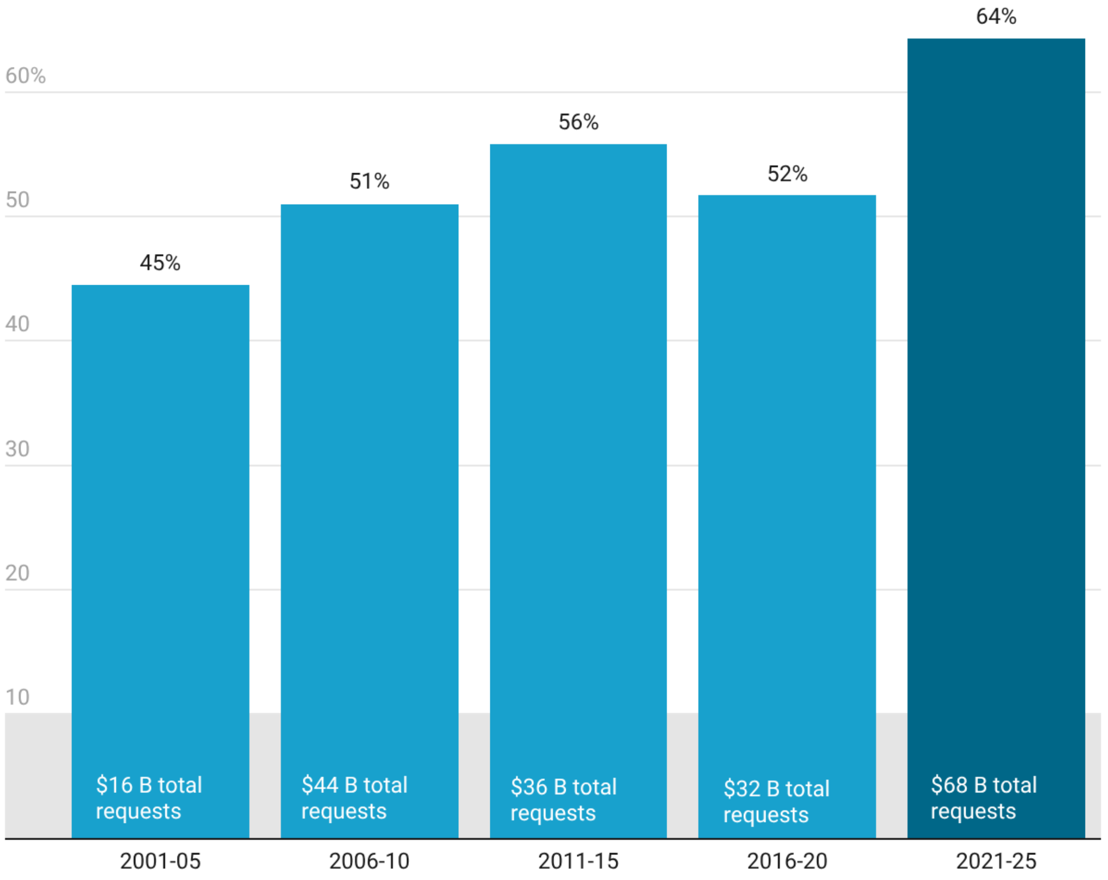
Count of rate cases in sample				
1981-90	**1991-00**	**2001-10**	**2011-19**	**2021-25**
667	274	412	649	404

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$.

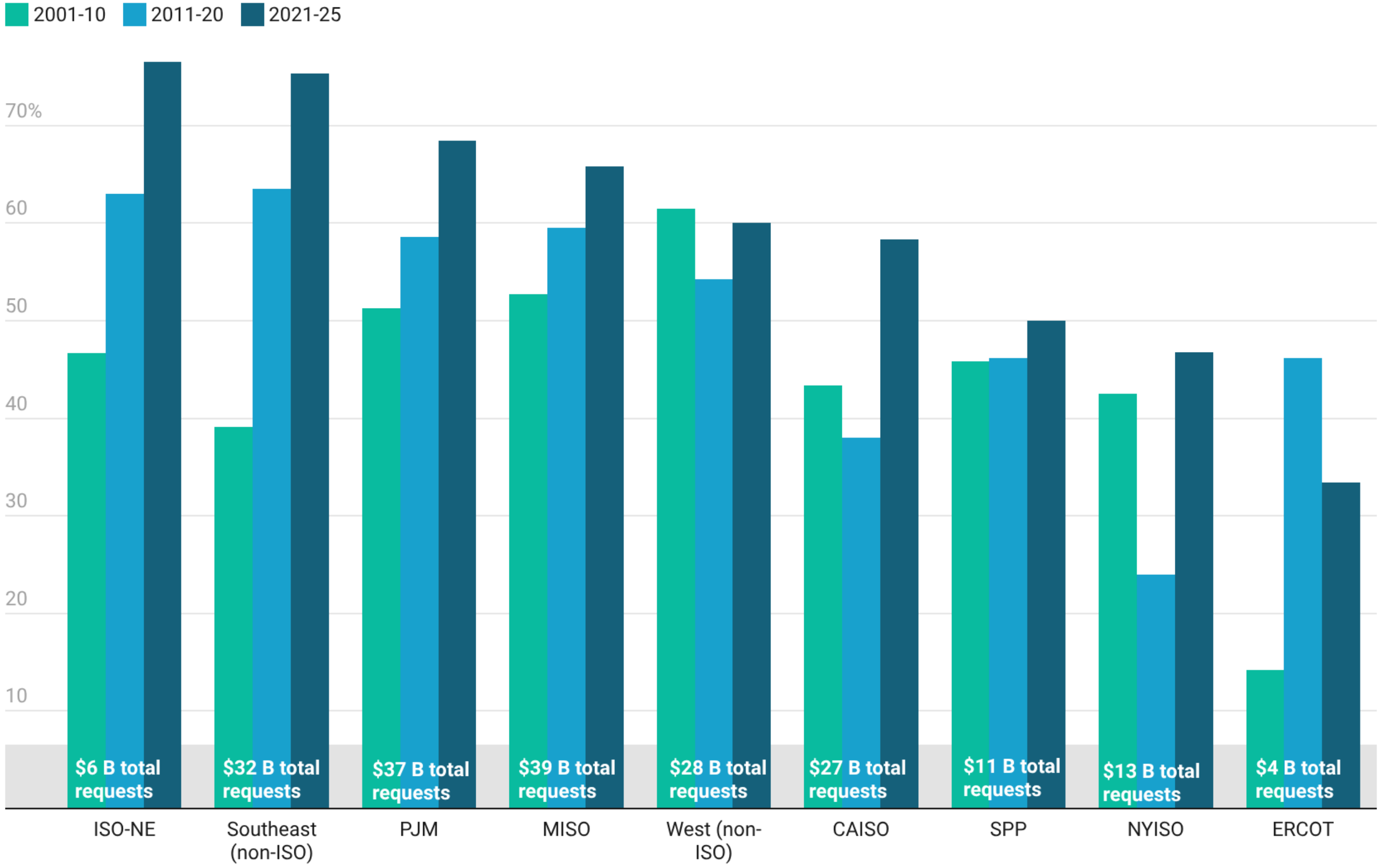
Source: S&P Global • Created with Datawrapper

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

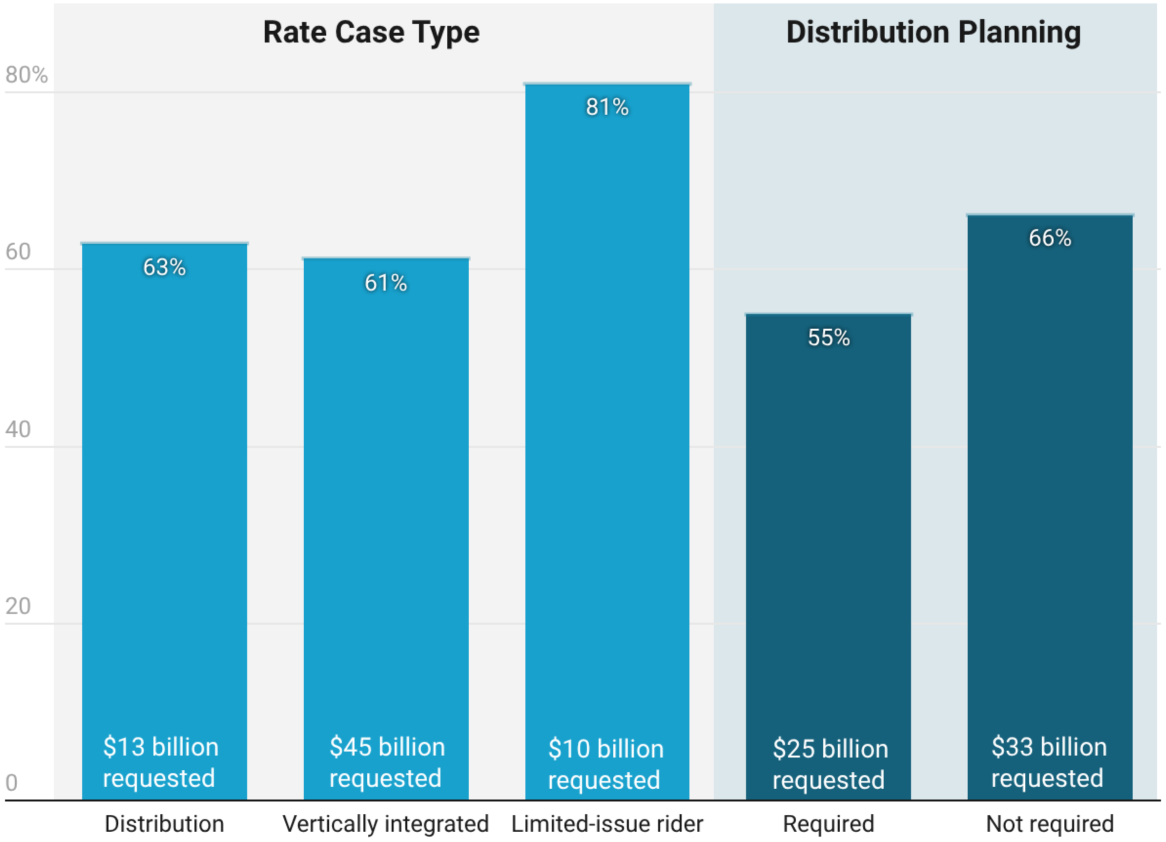
S&P data do not allow a focus solely on distribution-related requests, but the data can be segmented by somewhat-related characteristics

- Over the last five years, PUC approval levels for requests from “**distribution-only” utilities*** have been slightly higher than for “**vertically integrated” utilities***
- PUCs have approved much greater fractions of “**limited-issue rider”** requests, some of which are distribution focused (e.g., wildfire costs in California)
- Utilities with formal distribution-system planning requirement have seen requests receive lower levels of PUC approval than requests from utilities that lack such formal planning requirements—*reason for this descriptive finding is not clear*

*S&P labels general rate cases from states with retail market restructuring as “distribution” rate cases, aligned with the specific timing of the rate case and restructuring. These states are MA, NJ, OH, ME, CT, NY, NH, TX, PA, DC, MD, DE, IL, RI. Effectively all rate cases were labeled as vertically integrated cases prior to the 1990s.

Regulatory Approval Levels for IOU Rate Increase Requests

Approvals as a percent of rate increase requests, focusing on 2021-2025



Data presented as averages for each category, with each request weighted by its size; data related to distribution planning excludes the limited-issue rider requests. Total request amounts are for 2021-2025 in billion 2025$.

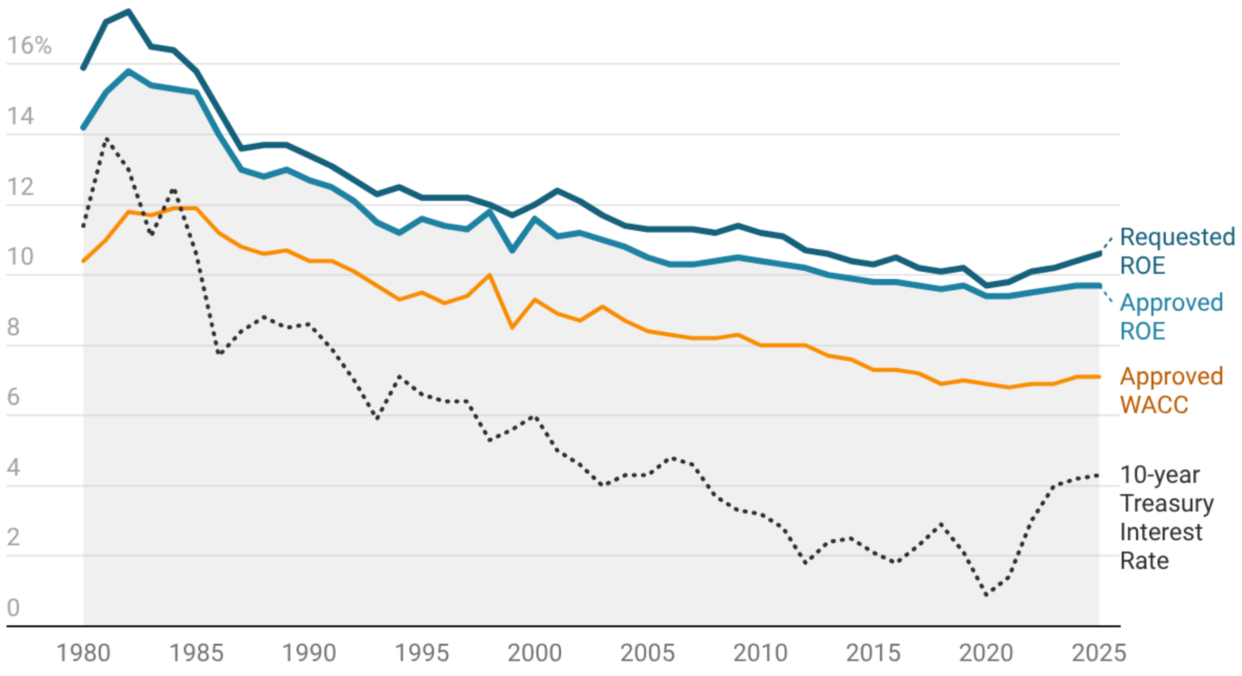
Source: S&P Global • Created with Datawrapper

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

- Avg. requested ROE in 2025 = **10.6%**
- Avg. authorized ROE in 2025 = **9.7%**
- ROE request levels and WACCs are correlated with interest rates
- Werner & Jarvis (2025) show that the gap between ROEs and various capital cost benchmarks increased during the 1990s and has remained sizable since though with some narrowing since 2020 as illustrated in the figure
- Following section discusses cost-of-service regulation, how ROEs are established, and related debates on possible incentive misalignment

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

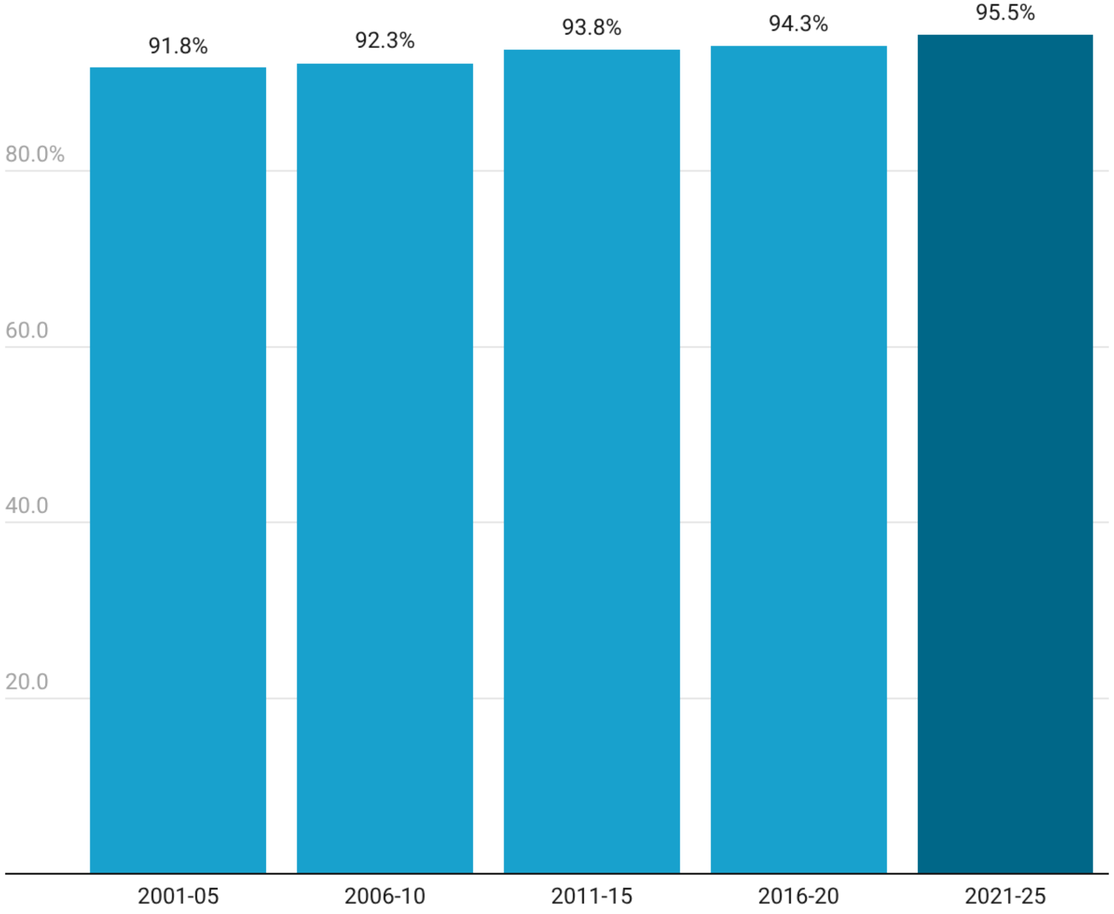
Note: Sample of 1,263 ROE requests and 1,045 ROE approvals in the 2001-2025 period are presented in this graph, along with 1,027 ROE requests and 989 ROE approvals in the 1980-2000 period.

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
- As with decisions on rate increase requests, 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

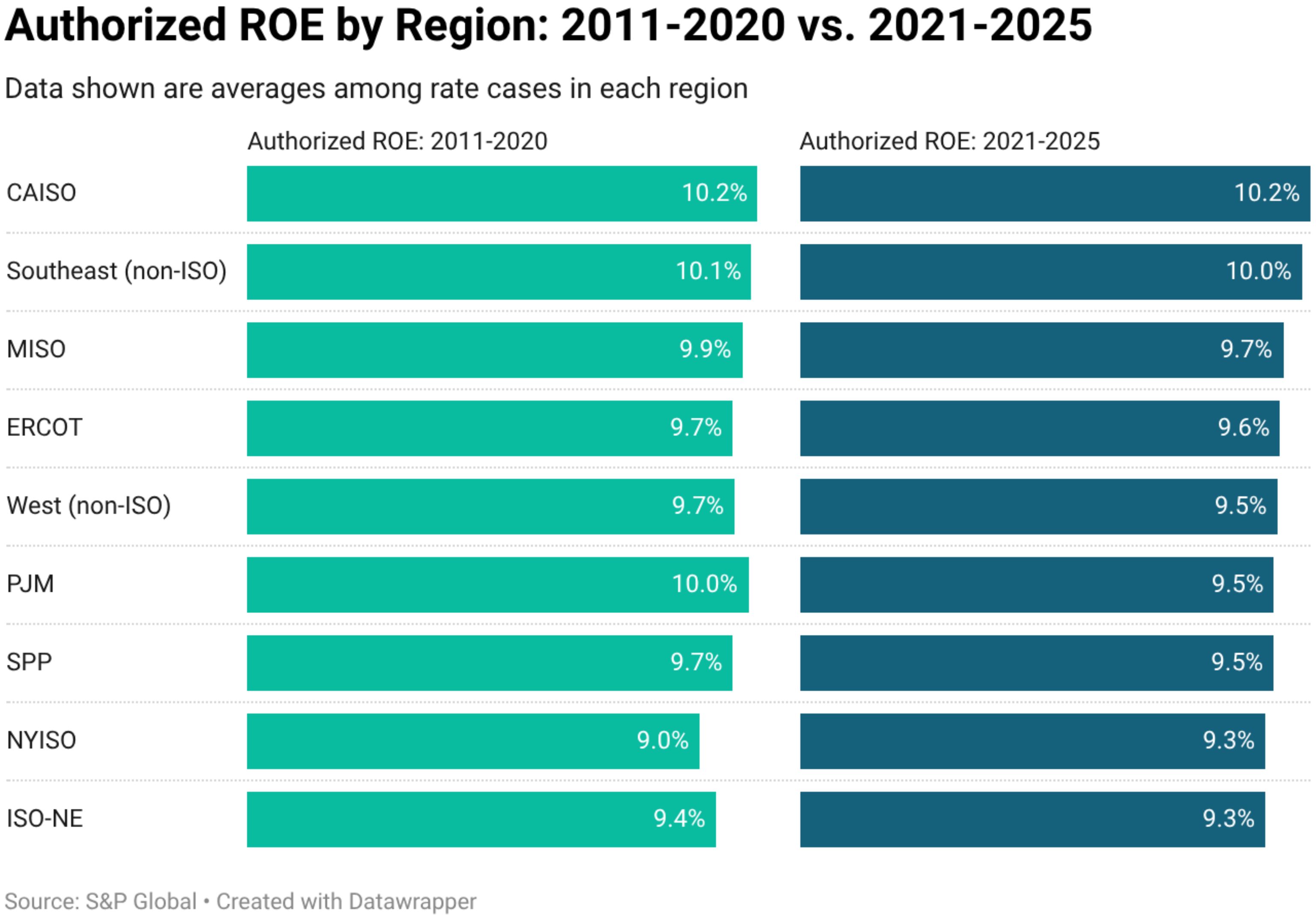


Source: S&P Global • Created with Datawrapper

*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)



Section 4:
Utility Regulation and Potential Incentive Misalignment

Key findings summary

1. There is empirical evidence that utility ROEs are generally higher than financial theory suggests necessary, leading to potential bias towards capital expenditures and higher prices
2. Prudency determinations are an important part of the regulatory process, but cannot always ensure that proposed and planned future benefits from investments are achieved
3. Although cost recovery tracker mechanisms seek to counter adverse impacts to utilities of regulatory lag, they can weaken incentives for operational and even capital cost containment

Section 5:
Regulatory Options to Manage Distribution-related Rate Increases

Objective and Methods

Objective

This section of the report summarizes strategies that state utility regulators can consider to ensure reliable local delivery of electricity at least cost.

Methods

- Identify primary tools that **state utility regulators** can use to manage distribution-related rate increases, split in two categories—**Incentives and Financing** **Planning and Analysis**—and based on three broad timeframes:
  - **Short term:** Impact immediately upon effective date of PUC decision
  - **Medium term:** 2–3 years
  - **Long term:** More than 3 years
- Review literature on efficacy of tools, examine pros and cons, provide examples, and describe regulatory considerations
- Scope **does not** include broader state legislative solutions (e.g., covering certain costs through taxes and public financing beyond securitization), federal policy options, or all regulatory options

Summary of regulatory options

Regulatory Tool	Description/*Potential Action*	Timeframe	Category*
Return on equity	Utility return on capital investments – *Reduce authorized ROE in rate cases*	Short term	I&F
Capital structure	Debt/equity ratio – *Approve capital structure different than what the utility requests in rate cases*		
Depreciation	Distribution asset recovery period – *If appropriate, consider longer depreciation periods to reduce near-term rate impacts (with the tradeoff of higher total costs)*		
Cost recovery trackers	Adjustments to revenue requirements and rates between rate cases for certain costs – *Limit use to costs outside utility's control, require earnings test, apply performance metrics, and use deadbands to limit cost adjustments*		
Construction Work in Progress (CWIP)	Includes construction costs as an asset in rate base immediately, before asset is in service – *Set budget caps, prohibit change orders, apply lower ROE for CWIP investments, or prohibit use*		
Securitization	Issue ratepayer-backed bonds at lower interest rate than utility's average cost of capital – *Consider for large projects*		
Performance-based regulation	Augment cost-of-service regulation to strengthen utility performance incentives - *Use multi-year rate plans to contain utility costs by reducing frequency of rate cases, and apply targeted performance incentives*	Medium term	I&F
Cost transparency in plans	Distribution plans provide the utility's roadmap for achieving reliability and other objectives – *Require detailed information on planned capital investments and expenses, including robust justifications*		P&A
Staged approval	Approve a portion of total project costs initially and review prudency of additional costs over time – *Discontinue spending (or cost recovery) if project is not delivering benefits used to justify costs*		
Cost-effectiveness evaluation	Conduct initial cost-effectiveness screening and prioritize expenditures – *Provide guidance on acceptable methods to justify planned investments and operation and maintenance expenses*		
Alternatives analysis	Consider alternatives to proposed capital investments – *Require utilities to consider all options for distribution expansion needs to identify least-cost solutions*		
Asset management	Utilities inventory existing equipment, analyze condition and performance, and prioritize spending decisions for system safety and reliability – *Closely examine justification for any changes, spending efficiency, and priorities*	Long term	P&A

*I&F - Incentives and Financing; P&A – Planning and Analysis

Conclusions

Summary of Key Findings

1. **IOU distribution spending** at a national level has been growing rapidly since 2014, representing **~30% of the total increase in average IOU retail rates**; regional spending growth has ranged from 2-8%/yr, with **larger rate impacts in CAISO, then NYISO & ISO-NE, then SE, MISO, PJM**

2. Some utilities are planning for **significantly increased distribution system spending**; planned spending on **managing the existing system** (asset replacement, safety & reliability, and resilience are all important drivers) exceeds that for **capacity expansion** (load growth is the dominant driver)

3. IOU **rate increase requests** and PUC **approval percentages** have recently hit **multi-decadal highs**; PUCs in New England and the Southeast have recently approved a greater fraction of rate requests, while PUCs in California and the Southeast have authorized higher equity returns

4. **Utility ROEs appear to exceed** levels implied by financial theory, potentially increasing prices and creating bias towards **capital spending**; cost-recovery **trackers** can further **weaken incentives** for cost containment; **prudency reviews help**, but regulators may be at an informational disadvantage

5. Regulators have **many tools to reduce distribution costs**; **shorter-term options** include those related to equity returns, capital structure, depreciation, trackers, CWIP, securitization; **medium-term** options include performance-based regulation and many planning-related requirements

For More Information

Contact: Ryan Wiser, rhwiser@lbl.gov

Other Publications

Download publications from the Energy Markets & Planning Department: https://emp.lbl.gov/publications

Acknowledgment

This work was funded by the U.S. Department of Energy's Office of Policy, under Contract No. DE-AC02-05CH11231. The authors thank Office of Policy staff for their feedback on the scope of this work, and comments on an earlier draft.

Disclaimer

Copyright Notice

Appendix Material

Electric utility distribution-system spending has been growing rapidly, with very different ratepayer impacts across various regions of the country

- Investor-owned utility (IOU) distribution spending* grew nationally by 6%/yr since 2014, in real dollar terms: 4x faster than the prior 20 yrs and consisting mostly of CapEx
- On a per-kWh basis, increases in IOU distribution costs since 2014 represent 32% of the overall national-average increase in retail electricity rates
- Larger distribution-driven rate increases have occurred in CAISO (~3 ¢/kWh since 2014, in real dollars), NYISO & ISO-NE (~1 ¢/kWh), then SE, MISO & PJM (~0.3-0.4 ¢/kWh), impacted by: (1) CapEx and O&M spending, (2) contraction in sales, and/or (3) shorter asset depreciation lives

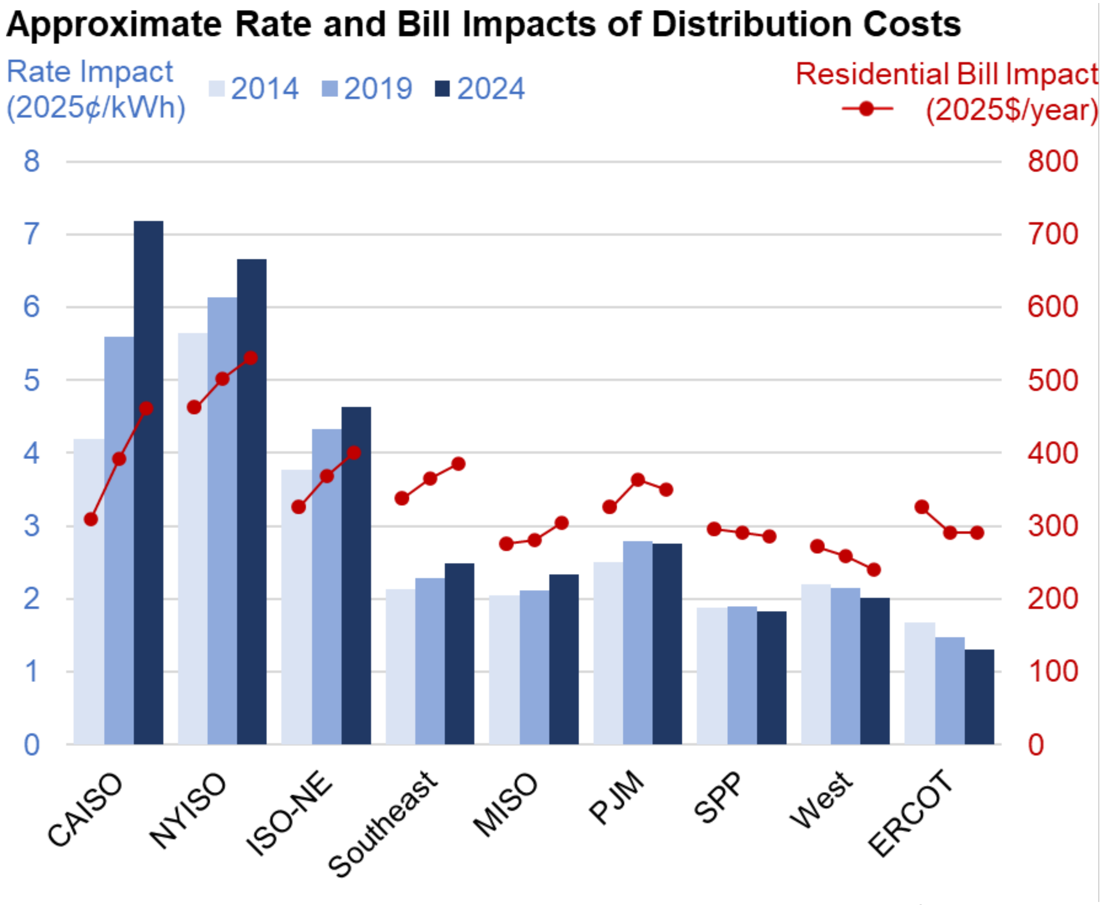
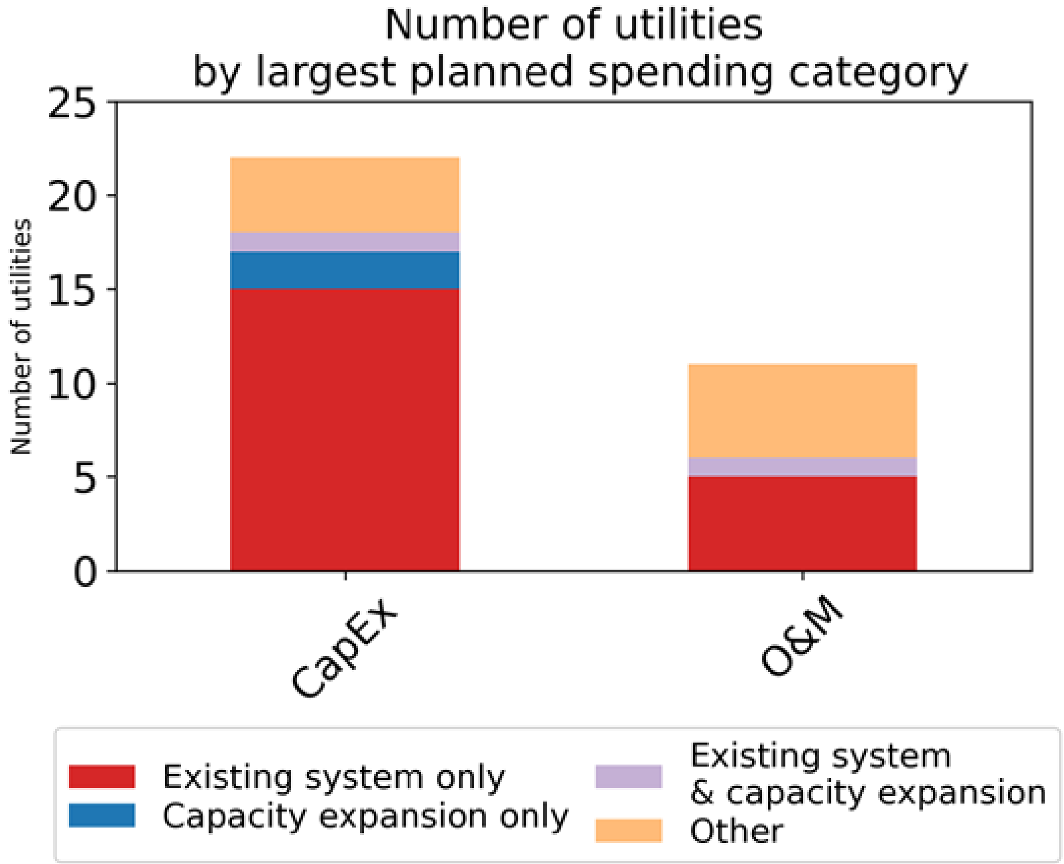


Figure notes: All values are 3-year rolling averages, and the resulting estimates in the figure should be considered rough approximations of rate impacts. See notes in a later section of this briefing for a more-complete accounting of the assumptions and uncertainties embedded in these estimates.

*** Includes distribution CapEx and infrastructure-related O&M; business operations, insurance, billing and other functions that utilities & regulators may allocate to "distribution" are not included in the figure or numerical results described here**

Section 2: Additional spending growth is planned, largely to maintain and enhance, rather than expand, the existing distribution system

- Many utilities are planning for significantly increased distribution-system spending through 2030
- Among a sample of 22 utilities, 15 identify managing the existing distribution system as the largest category of planned distribution capital expenditure (CapEx); capacity expansion is the largest CapEx category for just 2 utilities; costs for the existing distribution system also dominate O&M
- Asset replacement, safety and reliability, and resilience are all important drivers of CapEx for managing the existing system
- For distribution capacity expansion, load growth is the dominant driver of CapEx



"Other" spending includes operational and information technology, utility property, facility relocation, and workforce

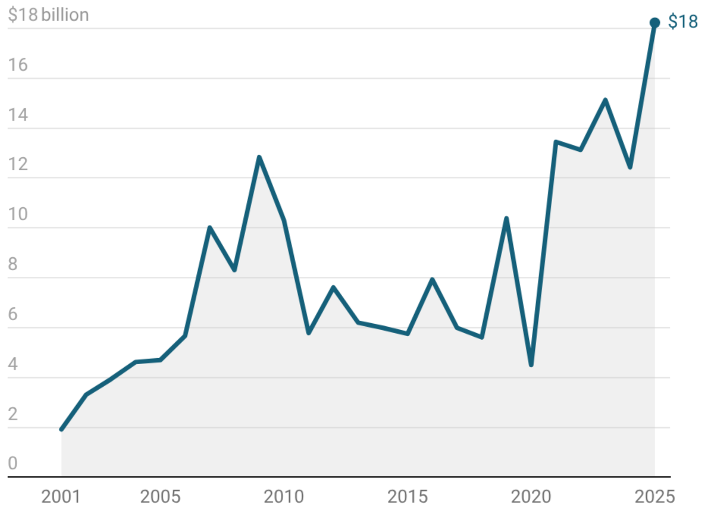
Rate increase requests and PUC approval levels have hit multi-decadal highs, implying further price increases absent policy or regulatory change

- IOU rate requests ($18 billion in 2025) and public utility commission (PUC) approval levels (64% of requested amounts from 2021-2025) have recently hit multi-decadal highs
- PUCs in New England and the Southeast have recently approved a greater fraction of rate requests (>75%), and approval percentages have significantly increased over time
- Approval percentages are also relatively high (and have recently increased) among PUCs in PJM and MISO; PUCs in ERCOT, NYISO & SPP had lower average approval levels (<50%)

IOU Rate Increase Requests

Investor-Owned Utility Rate Change Requests

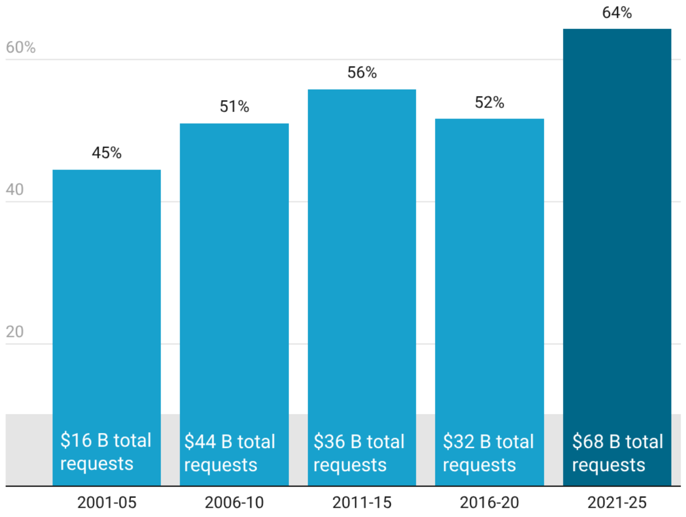
Billion 2025$



PUC Approval Levels

Approval Levels for IOU Rate Increase Requests

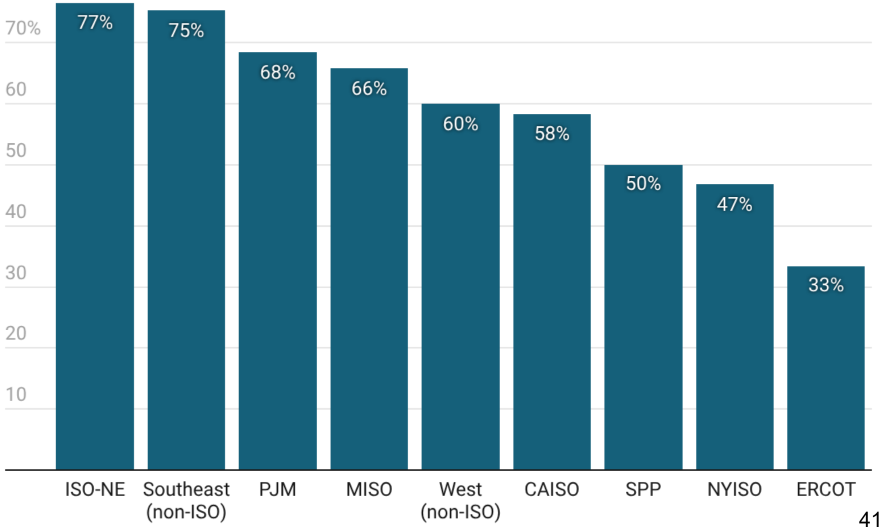
Approvals as a percent of rate increase requests



Regional Differences in Approvals

Regional Approval Levels for Requests: 2021-2025

Approvals as a percent of rate increase requests

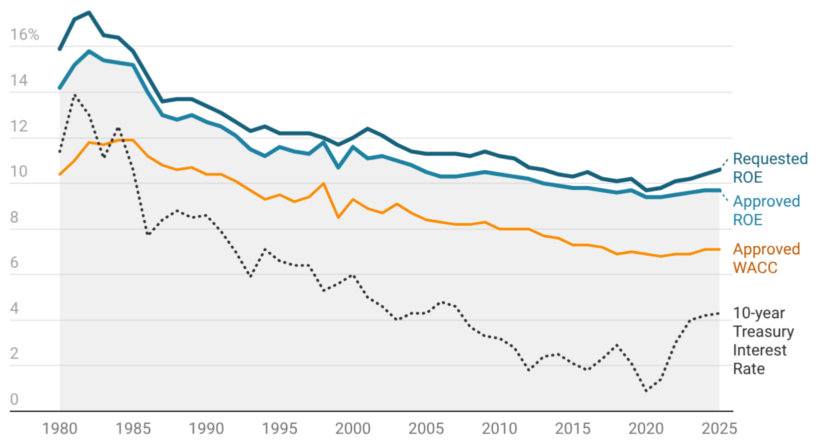


Cost-of-service regulation for IOUs can create utility incentives that are misaligned with least-cost electric service

- Recently authorized returns-on-equity (ROEs) are low relative to historical values, but have been trending up; authorized ROEs have been higher in CAISO & SE
- There is evidence that utility ROEs are higher than financial theory suggests are necessary, resulting in a bias towards CapEx over potentially cheaper OpEx solutions, which could lead to higher electricity rates
- Cost recovery tracker mechanisms have become more common, but risk further weakening utility incentives for cost containment if not carefully designed
- Prudency determinations by PUCs can help offset these two adverse impacts, strengthening incentives for cost reduction, but information asymmetry and limited capacity can put regulators at a disadvantage and future proceedings may be required to ensure that planned benefits from previous investments are achieved

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



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

Data shown are averages among rate cases in each region

Objective, Data and Methods

Objective

Electric utilities produce plans for distribution-system maintenance, enhancement, and expansion. This section compiles data from a sample of those plans to summarize planned CapEx and OpEx spending, identify underlying drivers, and generally characterize differences in planned distribution system spending across utilities.

Data and Methods

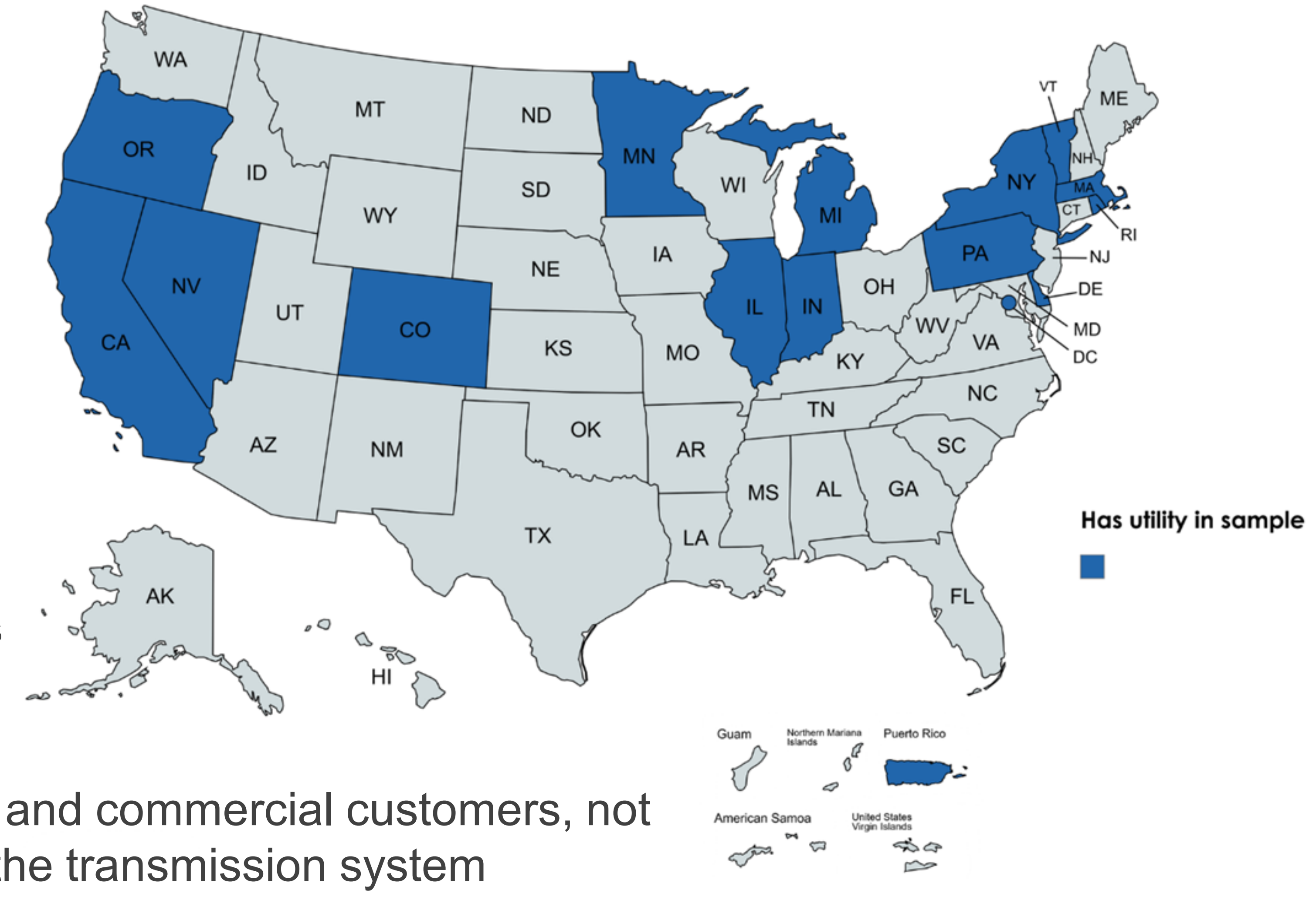
- **Data**
  - Collected planned distribution spending data from a sample of 22 utilities in 15 U.S. states and one territory; those utilities serve ~31 million customers (17% of U.S. total); planned spending is between 2020 and 2030; 21 utilities are IOUs and one is publicly owned (Morrisville VT)
  - Sources: distribution system, grid modernization, transmission and distribution investment, grid resource, and integrated resource plans
  - Recorded capital expenditures (CapEx) separately from operating expenses (OpEx); tracked reported drivers and illustrative examples of spending; converted all planned spending to $2025 using national CPI
- **Methods**
  - Mapped reported spending to standard categories based on reported drivers and descriptions of spending
  - Compared spending across utilities in terms of the (1) share of spending that is CapEx vs. OpEx, (2) share of spending by category, (3) growth in spending, and (4) spending per customer per year

Limitations and Caveats

- **Utilities included in the sample are in states with formal proceedings for some type of distribution system plan**
  - All utilities perform distribution system planning, but data are not as readily available for utilities in states that lack formal proceedings.
- **The planned spending we analyze may not reflect historical spending, all planned distribution spending, or spending that public utility commissions (PUCs) approve**
  - Many utilities in our sample did not report planned OpEx spending. PUCs may acknowledge plans they deem reasonable, but approval of expenditures in retail rates typically occurs in rate cases.
- **The granularity of planned spending data and the specificity of reported spending drivers varies by utility**
  - Reported spending categories may include multiple activities such as the replacement of damaged assets and increasing the capacity of equipment. Lack of granular reporting on spending and drivers makes it difficult to characterize individual utility spending and to compare spending across utilities.
- **We exclude reported spending for planned activities not typically classified as distribution system costs (e.g., customer programs), except that some spending for planned transmission is included due to an inability to separate it from distribution**

Geographically diverse sample captures planned distribution-system spending through 2030

- Data encompass **$67 billion of CapEx** and **$12 billion of OpEx** planned for 2020-2030
  - Planning periods differ, so we do not know how total planned spending changes over time in aggregate across the sample
- All 22 utilities report CapEx spending but only 11 report OpEx spending
  - For utilities that report both, CapEx is 80% of total planned spending on average and ranges from 65-99+%
- Spending largely serves residential and commercial customers, not large loads that connect directly to the transmission system



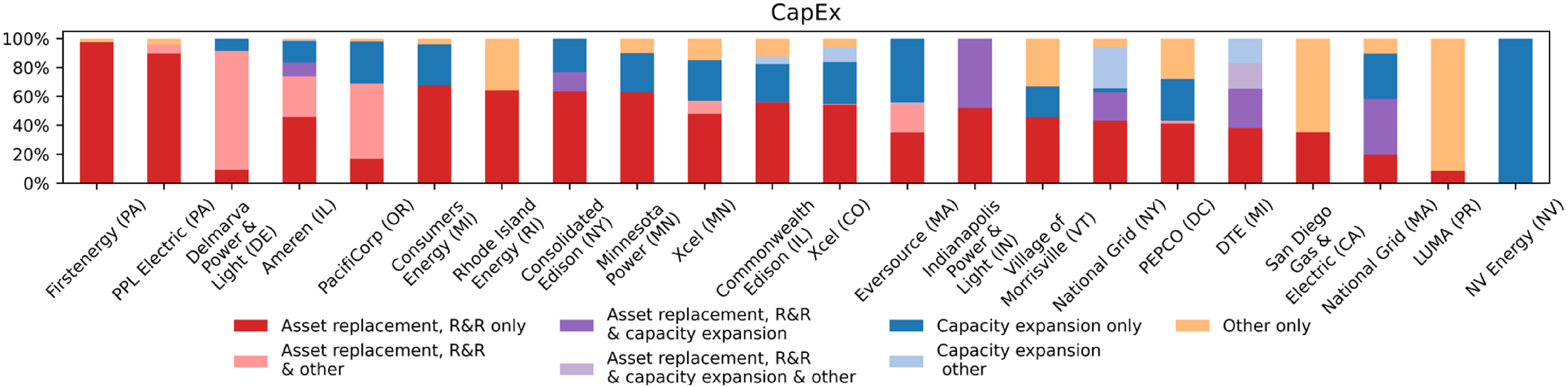
Data on planned utility spending complements historical investments tracked in FERC Form 1 as reported in the previous section

- FERC Form 1 shows what utilities **have invested in** whereas distribution system plans show **planned investments and related drivers**
  - Multiple drivers could explain spending in each FERC cost category (e.g., investments in station equipment could support asset replacement or load growth), but FERC data do not highlight drivers
  - The distribution system plans reviewed in this section enable a broad assessment of drivers (though those drivers cannot be matched to the FERC Form 1 spending categories)

We categorize planned spending into **three major categories** based on drivers described in utility planning documents:

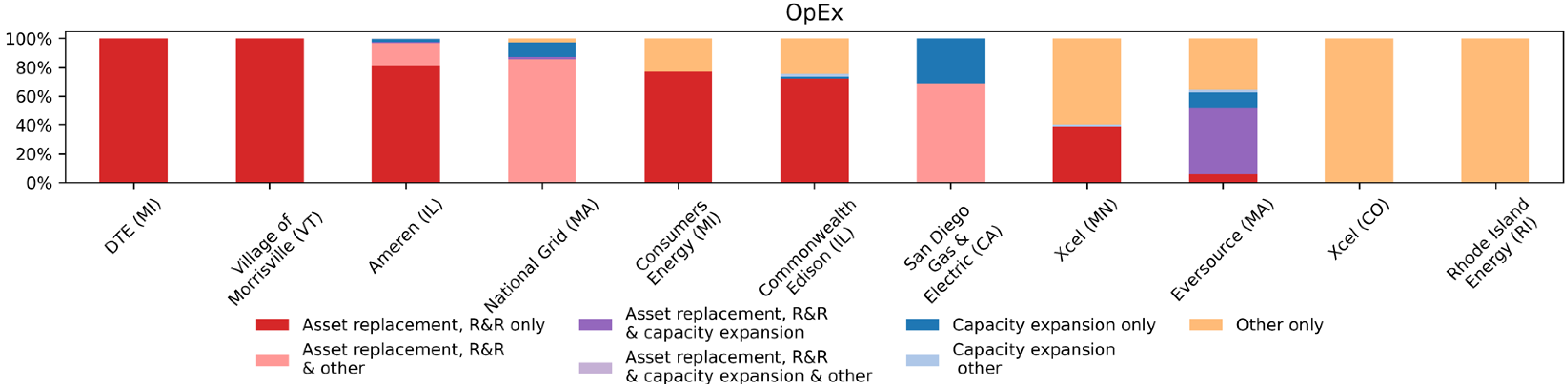
Asset replacement, reliability & resilience (R&R):	Capacity expansion:	Other spending:
investments to manage the existing system, e.g. replacing, repairing, and hardening	meeting expansion needs from load growth or distributed energy resource (DER) interconnection	operational and information technology, utility property, facility relocation, and workforce

For most utilities, planned CapEx spending on managing the existing distribution system exceeds planned spending on capacity expansion



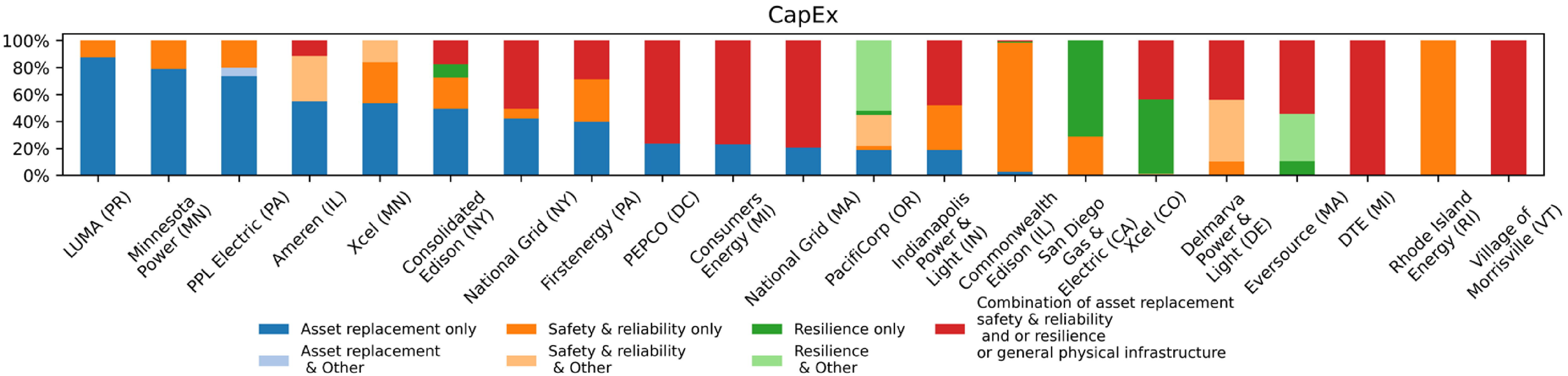
- **20 of 22** utilities plan to spend more CapEx on asset replacement, R&R (dark and light red in figure = existing system) than capacity expansion (dark and light blue in figure)
- Budget categories often have multiple drivers: (1) both ‘asset replacement, R&R’ and ‘capacity expansion’ (dark and light purple) and (2) ’other’ spending in combination with ‘asset replacement, R&R’ (light red) or ‘capacity expansion’ (light blue); for example, utilities may report spending for information technology such as SCADA systems (‘other’) alongside automated reclosers that support safety and reliability (‘asset replacement R&R’)

Utilities often provide less detail on OpEx than CapEx, but spending on the existing distribution system exceeds spending on capacity expansion



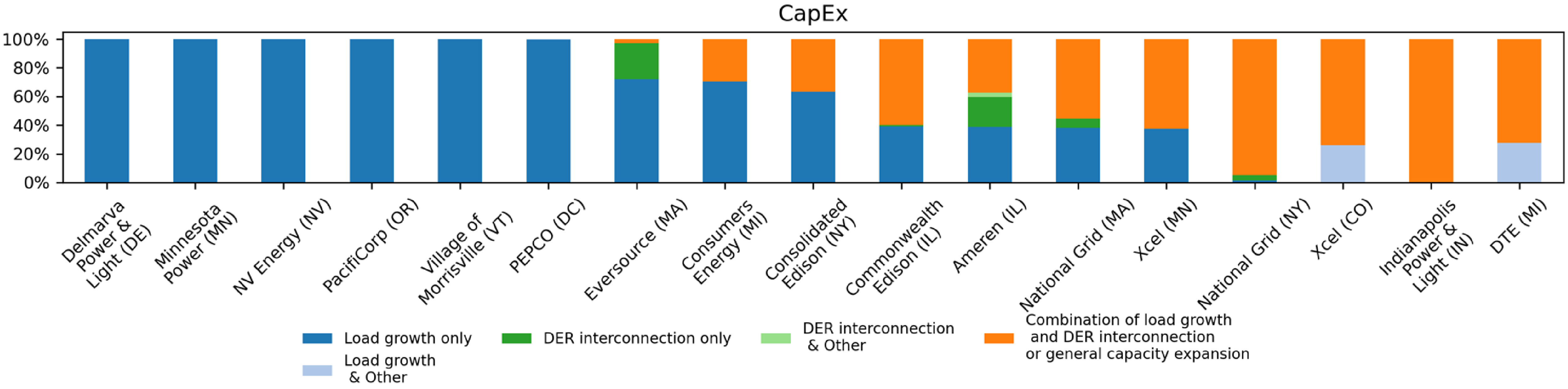
- **All 7 utilities** with sufficiently granular data plan to spend more OpEx on asset replacement, R&R (dark and light red in figure) than capacity expansion (dark and light blue in figure)
- Sample is limited: for some utilities, plans do not include all distribution-system OpEx
  - For example, DTE reports OpEx for tree trimming and preventative maintenance (both asset replacement, R&R) but does not report any OpEx for reported investments in capacity expansion
  - Another example: OpEx was < 0.5% of total spending for Xcel Colorado and SDG&E

The largest driver of planned CapEx on the existing system varies by utility but all are important: asset replacement, reliability, and resilience



- Within <u>asset replacement, R&R</u>, 'asset replacement,' 'safety and reliability,' and 'resilience' are each the largest planned CapEx driver in the existing distribution system for multiple utilities
- Often, we cannot determine how much spending is associated with each specific driver:
  - Some utilities report spending combined across multiple activities in the existing distribution system: e.g., Eversource's Reliability budget category combines hardening ('resilience'), replacing aging infrastructure ('asset replacement'), and upgrades that support reliable service ('safety and reliability')
  - Distribution system investments may have multiple drivers (e.g., a utility may replace an asset due to its poor condition with an upgraded version that is hardened for storms)

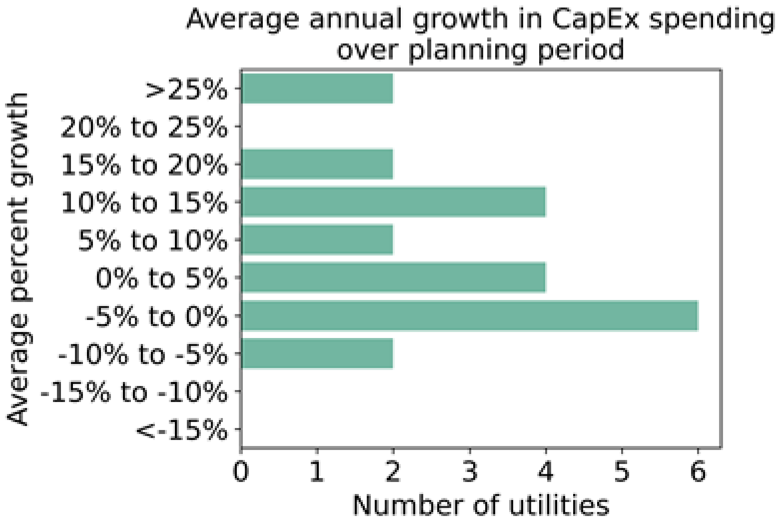
For capacity expansion, load growth is the dominant driver of utility distribution-system CapEx spending

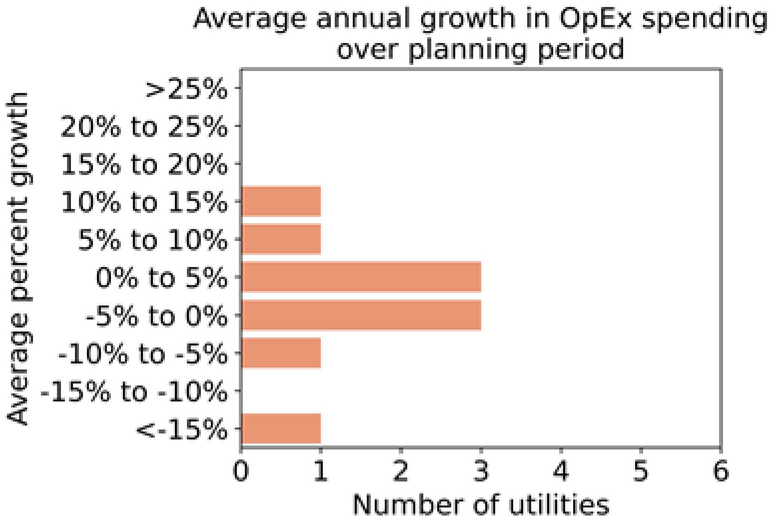


- **6 utilities** report that 99%+ of planned capacity expansion spending is on load growth
- Distinguishing the two drivers of capacity expansion CapEx is often difficult because utilities report combined spending across both activities (orange in figure)
  - For example, Xcel Minnesota reports spending for upgrades that accommodate new loads and increase hosting capacity for DER in a single budget category

Average annual growth in planned distribution system spending over utility planning periods varies widely, is greater for CapEx than OpEx

- **14 out of 22** utilities have planned distribution-system CapEx spending growth above the rate of inflation; 10 of those utilities expect spending growth above 5%/yr in real $ terms; 8 others have negative CapEx growth rates
- Large differences in spending growth across utilities, even in the same state, suggests that growth depends on the context of each utility territory; for example, annual CapEx growth:
  - ~14% for National Grid and ~1% for Eversource (both in Massachusetts)
  - ~12% for Ameren and ~2% for Commonwealth Edison (both in Illinois)
- CapEx growth exceeds OpEx growth for 8 of the 12 utilities that report both types of spending





Differences in the scope of reporting make it difficult to compare planned CapEx spending per customer across utilities

Variation in planned spending (and spending per customer) may result from:

Asymmetry in the types of costs reported: Utilities do not all use the same categories of distribution system spending in sources we reviewed.

- For example, as part of a grid resource plan, NV Energy only reports spending on improvements to substations that the utility determined had capacity constraints. This planned spending equates to ~$5 per customer per year.
- In contrast, in its distribution system plan, Xcel Minnesota's planned spending is $476 per customer per year. This spending covers a broad set of activities. Xcel Minnesota's planned activities include but are not limited to: replacing failed equipment, safety & reliability improvements, capacity expansion to support new customers, utility fleet purchases, facility relocations to enable public rights of way, and information/operational technologies.

Greater need for investment: Some utilities have older assets, greater storm impacts, more load growth, more line-miles per customer or grid modernization efforts, etc.

- Variation in planned spending per customer across utilities in the same state indicates differences in the need for distribution investment. For example, in New York, we calculate that Consolidated Edison and National Grid plan to spend $344 and $530 per customer per year, respectively.
- Standard budget categories within states could help PUCs compare spending *between utilities and within individual utilities* over time. See slide 66 for additional discussion of sharing utility data on distribution planning.

Review of “grid modernization” proposals identifies common rationales, objections, and factors that increase regulatory support

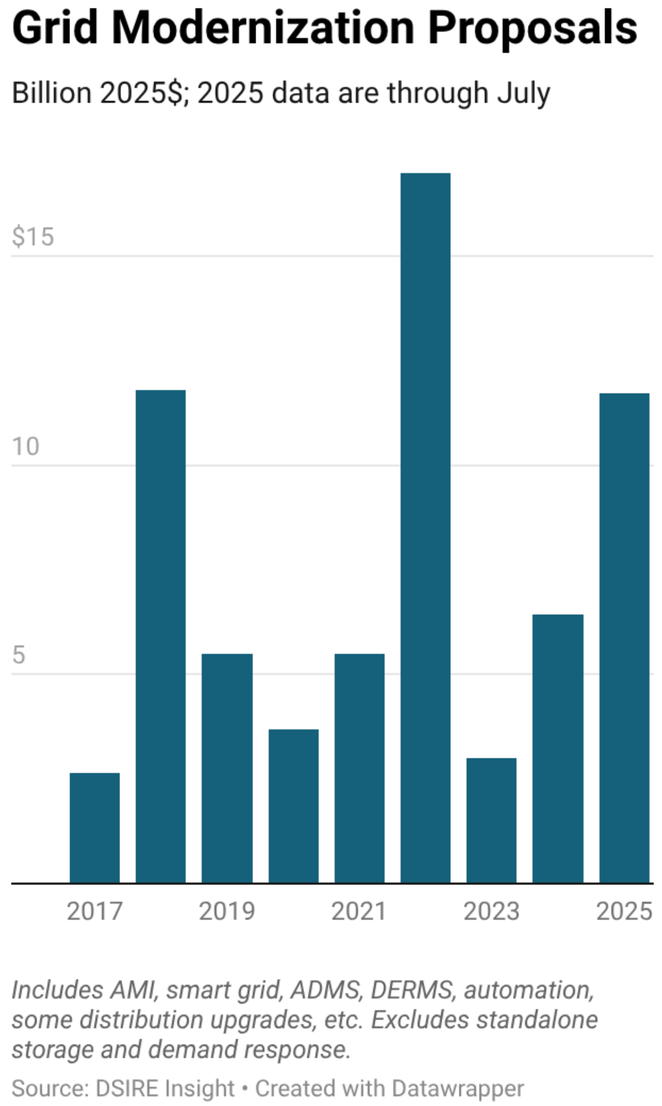
- DSIRE Insight data, focusing narrowly on a subset of mostly distribution-related “grid modernization” expenditures, identifies **$44 billion in proposals** across the U.S. from 2017-2025; however, ultimate approval and cost recovery are determined in **separate rate case proceedings**
- A recent LBNL report reviews a sample of IOU Grid Modernization requests and related regulatory feedback and ultimate resolution
- **Key finding:** Regulators are most-likely to support utility plans if aligned with state goals, robust cost-benefit analysis, evaluation of alternatives

Investment rationale of utilities: Improving reliability, resilience, customer control // Enabling achievement of state energy goals

Objections from reviewers: Insufficient information for technology or project on: investment costs, need, and timing // Most comments by Commissioners, PUC staff and consumer advocates focus on aspects of utility filings they disagree with

Topics of interest for Commissioners, PUC staff and consumer advocates: Timing of investments // Optimization // Transparency // Affordability

Proposals supported by utility regulators included: Clear linkages between grid modernization investment proposals, state policies and electricity planning processes (e.g., distribution system planning) // Robust cost-effectiveness analysis // Strong analysis of alternative investment options // Complete approval or disapproval of cost recovery for all grid modernization expenditures was uncommon.



Objective, Data and Methods

Objective

Summarize conceptual and empirical work assessing potential IOU incentive misalignment in cost-of-service (CoS) regulation as it relates to promoting least cost electricity. We focus on three outcomes of potential misalignment: (1) capital bias due to higher-than-necessary ROE; (2) lack of benefits realization in capital investments; and (3) lack of operational cost containment.

Data and Methods

- **Sources**
  - Stakeholder publications investigating investor-owned utility (IOU) regulation and impacts on utility incentives
  - Academic literature investigating utility incentive regulation
  - Diverse sample of state regulatory dockets and general rate case (GRC) proceedings, in part sourced by DSIRE Insight database
- **Methods**
  - Identify the rationale for three key components of CoS regulation: (1) ROE determination; (2) prudency determination; and (3) regulatory lag
  - Summarize concepts outlined in literature to illustrate the potential for incentive misalignment associated with these three key components
  - Present case studies from a representative sample of jurisdictions to provide examples of incentive misalignment for the three categories

Limitations and Caveats

- **Scope limitations**
  - Cost-of-service regulation and related issues are applicable to IOUs; this section does not address community-owned utilities or rural cooperative utilities (i.e., publicly owned utilities)
  - We have not performed an exhaustive collection and reporting of all U.S. rate cases or state-level experiences with utility incentive misalignment, nor an exhaustive review of related literature
  - Our mostly-qualitative approach limits our ability to calculate the average cost or average rate impact of these potential misaligned incentives, though we report a few studies that attempt to make these calculations for a subset of the potential incentive challenges
- **Caveats in interpretation**
  - Following slides are not limited to distribution expenditures as utility regulation and potential incentive misalignment can impact generation, transmission, and distribution costs for regulated IOUs
  - All statements are generalizations of U.S. regulatory experience, but any specific utility could have different outcomes or experiences depending on their specific state-level regulatory context

CoS ratemaking seeks to assign utility costs to customer classes and design rates to recover those costs based on "cost causation" principles

Step 1: Determine Revenue Requirement – Main Focus of this Section

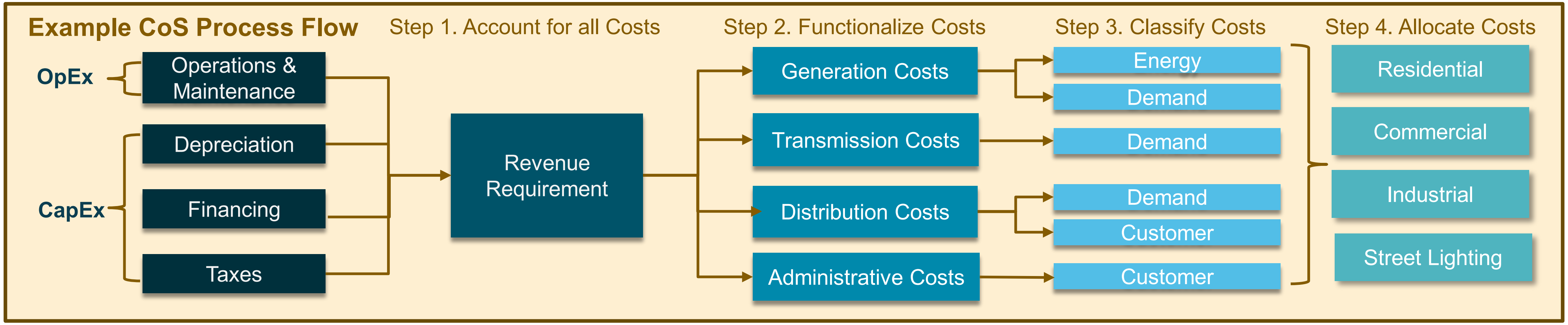
- A utility's base revenue requirement is established in a GRC, representing their costs to serve all customers including operations, maintenance, and infrastructure investments, and including a fair return to equity and debt providers
- Tracker mechanisms and rate riders are often used to adjust revenue requirement and rates between GRCs for certain costs
- Regulators aim to encourage least cost but must ensure safety, reliability, and quality of service
- **In the remaining slides, we assess 3 types of potential misaligned incentives that could lead IOUs to request higher revenue requirements than would be cost-optimal**

Steps 2 & 3: Functionalize and Classify Revenue Requirement

- These steps aim to answer this fundamental "cost causation" question: Which parts within the system led to the costs, and based on what driver?
- **Functionalization** is the process of assigning the components of the revenue requirement by function of the utility (i.e., generation, transmission, etc.)
- **Classification** aims to separate the functionalized costs by their primary cost driver, typically broken up into costs that vary with: (1) kW of demand (peaking needs), (2) kWh of energy consumed, or (3) number of customers

Step 4: Allocate Costs to Rate Classes

- Classified costs are allocated to each customer class based on their contribution to the primary cost driver
- Each class is meant to be a reasonably homogeneous group of customers who cause the utility to incur similar costs and who therefore face the same set of rates and rate structures



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

Determining a utility's authorized ROE starts with having a reasonable estimate of its COE; certain methods are supported more than others

- **Four methods to estimate COE** are commonly used in state regulatory proceedings to set authorized ROE, but there is **considerable debate** around how to appropriately apply these methods (Kihm, 2007)
- In 2019 & 2020, FERC issued a series of Orders (569, 569-A, 569-B) that ultimately eschewed the use of the Comparable Earnings method, in favor of the CAPM, DCF, and Risk Premium methods. In 2022, the DC Circuit Court rejected FERC's use of the Risk Premium method, leaving **FERC** to issue a final order identifying **CAPM & DCF as the only viable approaches for FERC-derived COE estimates** to set ROE.

Method	Description of Method	Advantages	Disadvantages	Sources
1. Capital Asset Pricing (CAPM)	COE equals risk-free return (e.g., Treasury bonds) plus a risk-adjusted premium using market returns	• Based on financial theory • Mathematically simple	• Risk premium difficult to estimate	• NARUC, 2019 • RAP, 2023
2. Discounted Cash Flow (DCF)	COE equals dividends divided by stock price plus expected dividend growth rate	• Based on financial theory • Mathematically simple	• Growth rate not observable	• NARUC, 2019 • RAP, 2023
3. Risk Premium	Compares historical difference between peer-utility authorized ROEs and bond yields	• Conceptually simple	• Not based on finance theory • FERC prohibited use	• Ellis, 2025 • RAP, 2023
4. Comparable Earnings	Forecast of future ROEs based on historical returns awarded to peer utilities	• Conceptually simple	• Not based on finance theory • FERC prohibited use	• Ellis, 2025 • RAP, 2023

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

The broader literature identifies several possible reasons for why authorized ROEs may exceed COE estimates:

Utility Advantages	Inappropriate Input Data	Circular Methods	Regulator Incentives
Asymmetry in information, expertise and resources between IOUs and regulators and consumer advocates, leading to ROEs & timing of changes that advantage IOUs	Inaccurate forecasts of interest rates, growth rates, and betas (i.e., measure of relative utility risk) that are critical inputs to calculating COE via CAPM and DCF methods	Relying on past ROEs of the same or other (peer) utilities to determine updated ROEs, thereby not adjusting ROEs based on financial fundamentals and true COE	(1) Prioritizing total costs over individual drivers; (2) Risk aversion and desire to avoid underinvestment that could degrade reliability; (3) Relative political power of regulators vs. IOUs

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

- Werner and Jarvis (2025) suggest U.S. electricity costs are $3-11 billion per year (in 2025 USD) higher than they should be, which roughly equates to a rate impact for IOUs of 0.2 ¢/kWh – 0.8 ¢/kWh
- Daniel et. al. (2025) estimate 1 percentage point reduction in ROE = $4 billion per year U.S. electricity bill savings

Prudency determinations conceptually promote least-cost provision of electricity service, but opportunities exist to undermine this outcome

Regulators evaluate during rate cases or other reviews whether utilities "prudently" incurred OpEx and CapEx. This can result in regulators disallowing utility recovery of previous expenditures, thereby reducing the revenue requirement and potentially authorized earnings. But…

- **Benefits realization can be difficult to ensure**: Even if expenditures are deemed prudent for cost recovery in rates, the resulting reductions in the utility's costs may not manifest for some time and may require additional deliberate utility action to achieve.
- **Information asymmetry and limited capacity put regulators at a disadvantage**: Utilities hold the data needed by regulators to review expenditures for prudency. Many regulatory agencies are understaffed and overworked, which may limit their ability to request the correct data from the utility, evaluate the data once received, and interpret the results to make an appropriate determination.

CoS Regulation has Limited Visibility into Future Benefits Realization: Examples from Grid Modernization Initiatives

Timing mismatch

Costs are immediate but benefits accrue after regulatory decisions.

- Forward-looking benefits are estimated over asset lives, but rate cases primarily rely on historical data; costs appear immediately, while many benefits materialize after rate cases are decided (DOE AMI Compendium, Joskow (2008))
- Some benefits are realized years after deployment and depend on operational maturity (Vilaplana et al (2025), AMI Semi-Annual Metrics Report)

Tracking focuses on deployment

Regulatory oversight typically emphasizes assets installed, not outcomes or cost reductions achieved.

- Regulatory oversight often counts what is enabled or installed, such as tracking devices, circuits, and DERs enabled, but not costs avoided or benefits realized (MA D.P.U. 21-80-82-A, Guidehouse ADMS & DERMS reports)
- Some programs report reliability outcomes, such as customer minutes of interruption saved, but often include limited analysis of economic benefits (MA Advanced Distribution Automation Report)

Methods limit benefit recognition

Some benefits lack accepted post-deployment measurement methods.

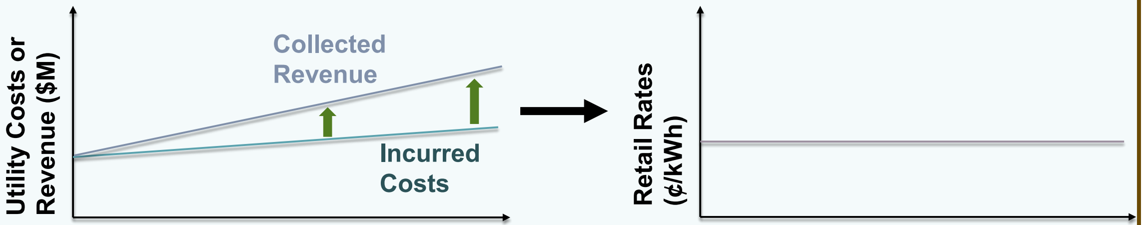
- Some benefits lack accepted calculation methods and thus go unreported (CA DRP avoided cost White Paper, Entergy AR Docket 16-060-U)
- Benefits may be labeled "sensitive" or sealed, limiting regulatory visibility and use (Entergy AR Docket 16-060-U)
- Some metrics, such as avoided capital costs or load reduction, mentioned in business plans are not systematically reported post-deployment (Entergy AR Docket 16-060-U - Testimony)

Regulatory lag encourages utility cost-control between rate cases, but opportunities exist to undermine this outcome

- Utility base rates are changed during GRCs, which must be initiated by a utility or (far less often) by a regulator (note: often there is no prescribed schedule for when these are initiated)
- Once base rates are set in a GRC, they are maintained until the next GRC, leading to a lag between intermediate changes to utility costs or sales and when a utility updates rates to reflect those changes
- Regulatory lag incentivizes a utility to maximize sales (and revenue) and minimize costs between GRCs

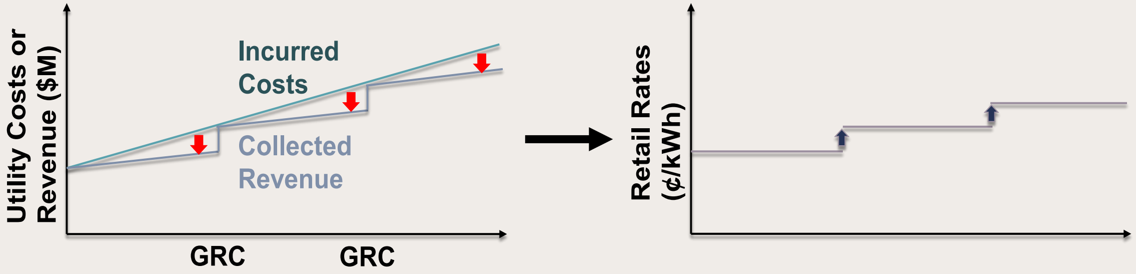
Regulatory Lag Excess Profits Case

- If a utility's collected revenue growth > incurred cost growth, then the utility earns excess profits between GRCs
- In this case, incentives to cut cost in the short-term between GRCs **can sometimes lead to adverse long-term impacts** (e.g., more frequent or severe wildfires due to lack of vegetation management)
- Also, a utility would prefer to keep, not lower, rates at their current level by **not filing a GRC and thus maintaining excess profits**; the onus is on regulators to compel the utility to file a GRC



Regulatory Lag Profits Erosion Case

- If a utility's collected revenue growth < incurred cost growth, then the utility earns lower profits than authorized in a GRC
- Example: some costs are difficult for a utility to manage in the short-term (e.g., distribution station transformer costs are hard to predict)
- Utility prefers to file a GRC to increase rates, but may need to wait more than a year to get relief without ability to recover lost earnings → **can motivate between-GRC rate adjustments (see next slide)**



Between-GRC cost recovery and rate adjustments ("trackers" or "riders") seek to address shortcomings, but can have unintended consequences

Adjustment to CoS Ratemaking	Conceptual Assessment	Empirical Evidence: Examples
Operational Cost Recovery Mechanisms Cost recovery mechanism to ensure more timely recovery of operational costs *Examples: Fuel Adjustment Clauses (FAC) found in 37 states*	• FACs can change firms' incentives by decoupling price adjustments from CoS ratemaking, which can distort technology and fuel use (Baron and De Bondt, 1979). • FACs may bias utilities toward greater fuel use and weaken incentives to search for lower-cost fuel, leading to higher effective fuel costs (Costello, 2009).	• ComEd removed its FAC in 1997 and immediately took actions (contract buyouts, switching to lower-cost coal) that led to substantial reductions in fuel costs by 10-15%, on average (Cicala, 2021). • Price-regulated coal plants, which typically have FACs, were found to store about 9% more coal than comparable market-based coal plants (Jha, 2024).
New Capital Expenditure Recovery Mechanisms Cost recovery mechanism that allows recovery of new capital costs outside a general rate case *Examples: Construction work in progress (CWIP), Allowance for Funds Used During Construction (AFUDC) and similar mechanisms found in 41 states*	• These mechanisms can improve utility cash flows and can reduce project financing costs. • But they may weaken incentives for strict cost control and expose current ratepayers to cost overruns (Olson et al, 2025).	• Approved at ~$14 billion in 2009, total costs for Plant Vogtle Units 3 & 4 rose to ~$39 billion by 2024, with customers paying via CWIP years before receiving power (Olson et al., 2025). • GAO (1980) documents that CWIP grew from 8.3% of net capital investment in utility plant (1967) to ~25% (1978). 31–33% of CWIP was included in the rate base, shifting construction risk onto ratepayers.
Lost Revenue Recovery Mechanisms Tracker mechanism to ensure more complete recovery of authorized revenue requirement *Examples: Decoupling mechanisms found in 28 states*	• Decoupling allows utilities to maintain revenue even when sales decline. It was intended to remove utility disincentives for supporting energy efficiency. • It has sometimes been criticized for appearing to guarantee revenues regardless of sales levels (The Regulatory Assistance Project, 2011).	• There is extensive literature documenting strategic behavior under decoupling mechanisms, such as utilities inflating sales prior to decoupling to affect the revenue baseline that determines future earnings (Loessl and Wetzl, 2022). • However, there are no empirical studies that examine whether decoupling weakens incentives for cost containment.

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%

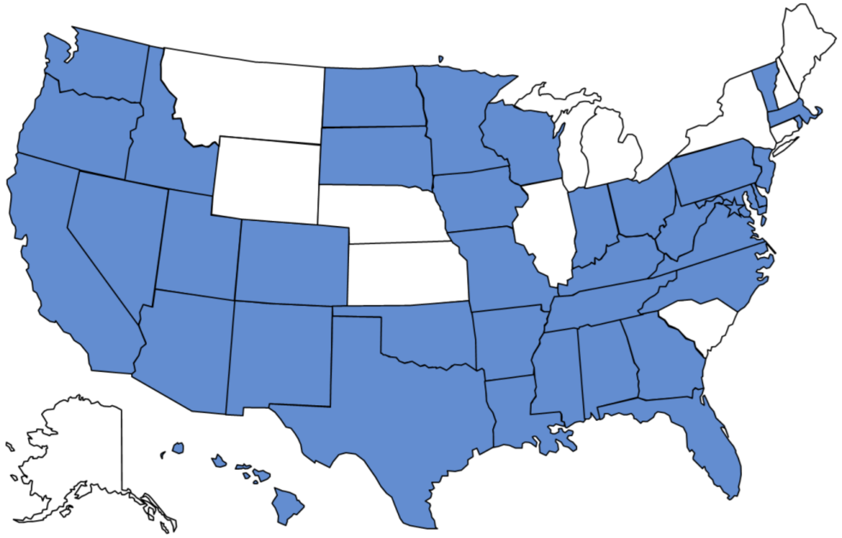
Short term

Reduce use of cost recovery trackers (also called riders)

Incentives and Financing

- These trackers expedite utility recovery of certain costs that change between rate cases
  - Tracked costs are removed from base retail rates, typically reset in GRCs, eliminating "regulatory lag" and concurrent review with all other elements of revenue requirement for overall cost reasonableness
  - For distribution, trackers are sometimes used for grid modernization, substations, replacement of aging assets, resilience, and vegetation management (for examples, see Table 2 here)
- The closer utility revenues track costs via trackers/riders, the weaker the incentive to contain costs because rates are adjusted between rate cases
- **Regulatory options** to strengthen cost control:
  - **Limit use** of trackers to cases with strong justification (i.e., costs clearly outside the utility's control)
  - Require an **earnings test** to evaluate utility financial performance before tracked costs are included in retail rates (e.g., surcharges allowed only up to utility's authorized ROE)
  - Apply **performance metrics** for approving tracked costs
  - **Use deadbands**, adjusting rates only for tracked costs outside a predefined range

Recent Electric Utility Capital Cost Trackers



Source: Lowry et al. (2024)

Short term

Scrutinize requests for Construction Work in Progress

Incentives and Financing

- Most utilities recover prudently incurred capital and operating costs for ***in service*** plants
  - Under Allowance for Funds Used During Construction (AFUDC), an asset is not included in the rate base until it is used and useful; accumulated carrying costs are added to CapEx and depreciated over the asset's useful life
- CWIP treats construction costs as an asset in rate base immediately; utilities earn revenue before the asset is in service, and retail rates increase as the utility incurs financing costs
  - Customers cover carrying costs while project is under construction, shifting risk from investors
  - Incents capital-intensive projects (CWIP focus) & longer timelines (reduces incentive to complete project timely)
  - But can lower revenue requirement over asset life because carrying costs during construction are not capitalized
  - Often used for generation and transmission; use for distribution is far less common though examples exist
- **Regulatory options** to strengthen cost control:
  - **Budget caps** and prohibition of change orders - Protect ratepayers from cost overruns (see Vogtle example on slide 57)
  - **Lower ROE** for CWIP investments - Reduce costs to customers to reflect reduced shareholder risk
  - **Prohibit CWIP** - Protect customers from paying for projects that may never be completed or are not needed if projected electricity demand does not materialize

CWIP examples for distribution:

- CenterPoint (IN) Transmission, Distribution and Storage System Improvement Charge
- FL storm protection plans

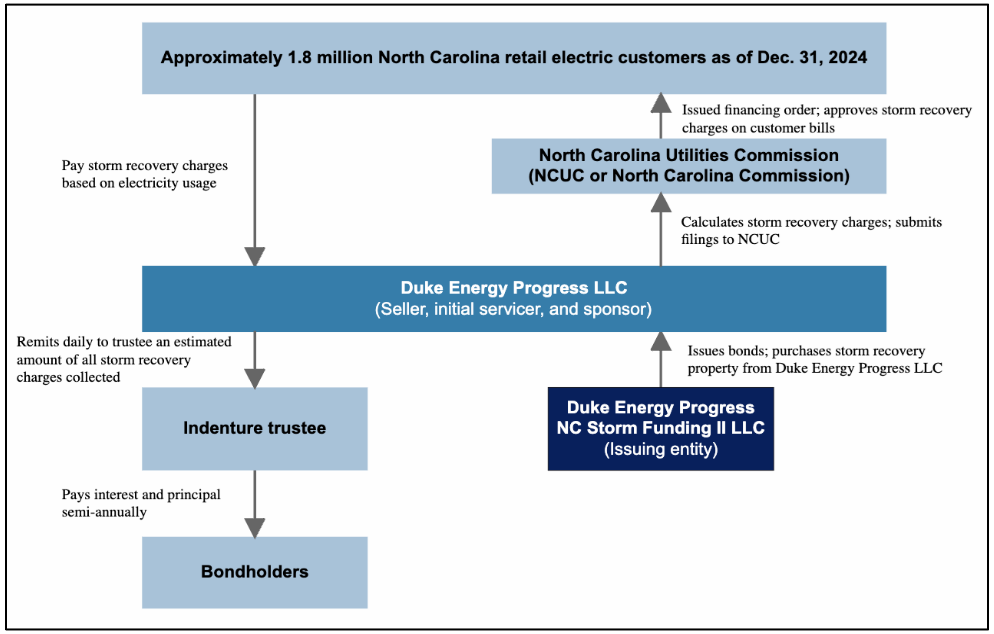
*Short term**

Selectively use securitization for certain utility costs

Incentives and Financing

- Utility sells bonds for specific costs to a special purpose entity, which in turn sells bonds in the market at an interest rate that is lower than the utility's cost of equity
  - Securitization also may spread cost recovery over a longer period and reduce costs associated with taxes on earnings
  - Utility customers repay bonds through their electric bills
- Provides savings when applied to investments (i.e., CapEx), compared to traditional utility financing
  - But when used for operating expenses, increases total costs because there is otherwise no ROE on these expenses
- Securitization requires state legislation (*)
  - Including provisions for non-interference and periodic bill adjustments to ensure investors will be repaid, bonds receive a high credit rating, and financing costs are minimized
  - Legislation and the terms of bond issuance may also be scrutinized for consumer protection and maximum cost savings
- Past uses of securitization were typically for unexpected costs such as storm recovery and wildfires, as well as large infrastructure projects and stranded assets

Transaction structure for Duke Energy (NC)



Source: S&P Global

Examples of estimated savings:

- $465M for PG&E's $1.4B securitization for wildfire hardening investments
- $143M for Duke Energy's $556M securitization for Hurricane Helene expenses

*If state enabling legislation is in place

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]
  - PBR also includes performance incentive mechanisms, decoupling
- 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.

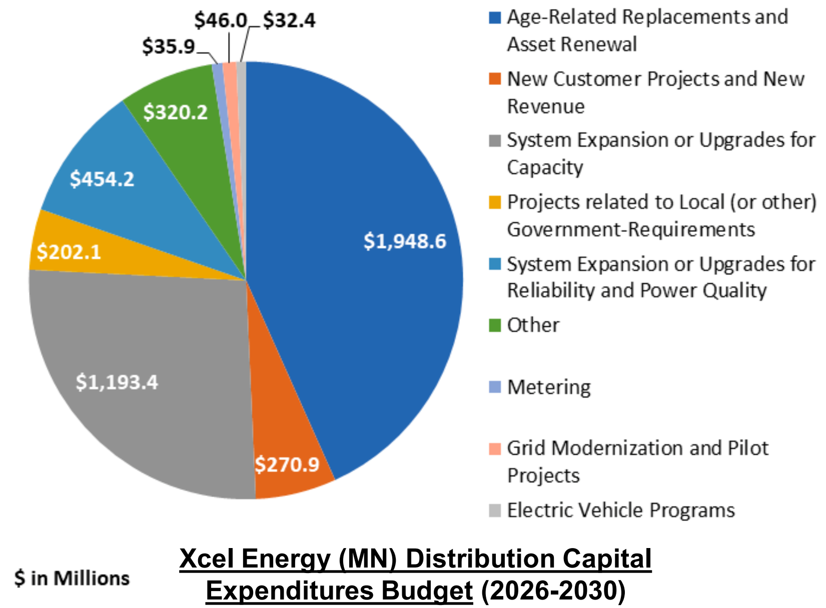
Require transparency of data and planned expenditures

Planning and Analysis

- Providing a longer-term, holistic picture of existing and planned distribution system investments before they show up in individual rate cases facilitates regulatory and stakeholder review and improved oversight of distribution system costs
  - Distribution data and analyses are useful for the review of proposed utility programs and retail rates; they also enable consumers and third-party providers to propose alternative, potentially less costly, solutions
- Utilities conduct extensive analysis to develop distribution system plans, but regulators and stakeholders in most jurisdictions do not know what data are available, how the utility uses the data in planning and investing, and how the utility evaluates and prioritizes investments
- Sharing information in distribution plan filings provides transparency into the utility's planned capital investments and operation and maintenance expenses
- Regulators can balance the need for information to support regulatory decision-making and stakeholder engagement with the volume of information that utilities are required to submit

Examples:

- IL requires utilities to file 5 years of historical and forecasted financial data for distribution investments organized by investment category, among other data requirements, as part of their multi-year integrated grid plans
- MN also has detailed cost transparency requirements



Xcel Energy (MN) Distribution Capital Expenditures Budget (2026-2030)

Review initial performance for cost recovery and future plans

Planning and Analysis

- Spending for large distribution projects may occur over several years and multiple planning proceedings, providing opportunities to discontinue spending (or cost recovery) if the investments are not delivering the benefits used to justify costs
- Regulators can approve a ***portion*** of total project costs initially and review prudency of additional costs over time
  - Approval can be staged based on interim utility performance (e.g., delivering claimed benefits for the initial investment)
- Utilities can conduct intermediate assessments of initial progress and adjust plans accordingly
  - Assess whether initial projects met planned objectives
  - Use insights to refine strategic direction

Example: For Georgia Power's 2022 rate case, the PSC approved preliminary steps* for a Distributed Energy Resource Management System (DERMS)—an investment need identified in the integrated resource plan (which includes distribution planning)—deferring approval of the balance until the next rate period

*System modifications for DER modeling and visibility, integrating modifications with real-time operations platforms (e.g., SCADA, distribution management system), and capabilities for DER remote configuration

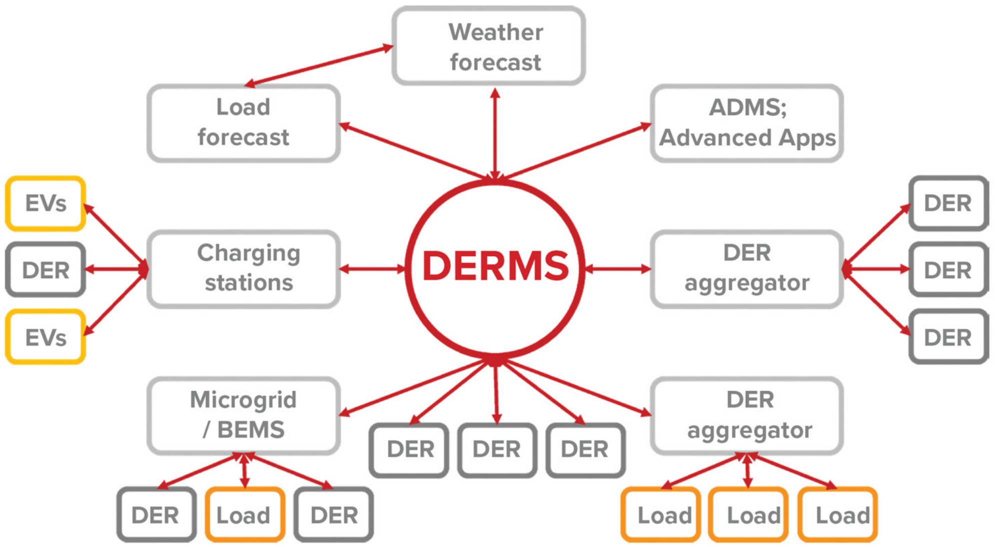


Figure source: Quanta Technology

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	

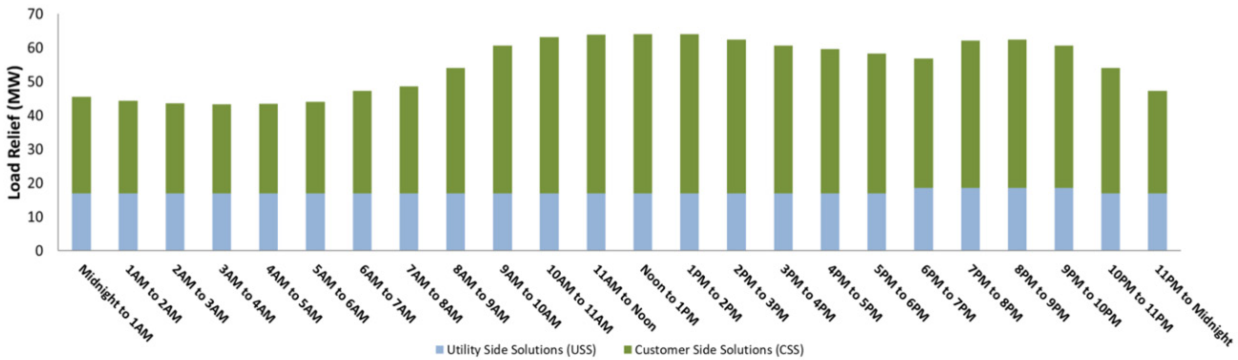
Medium term

Require alternatives analysis for distribution expansion

Planning and Analysis

- Regulators can require utilities to consider all options for distribution-system expansion 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

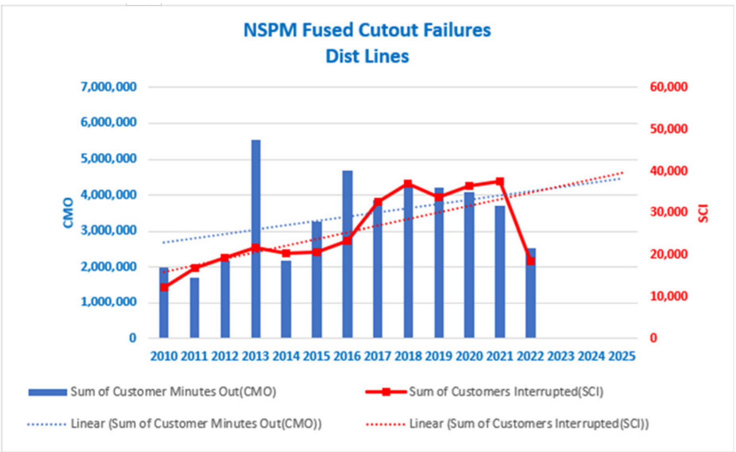
Improve asset management strategies

Planning and Analysis

- Utilities must address needs related to existing infrastructure, not just needs related to system expansion
- Utilities inventory existing distribution system assets, analyze condition and performance, and make capital and maintenance spending decisions for system safety and reliability
  - Programmatic investments address repeating system needs, remediating widespread issues over time, or scaling up deployment of new technologies (e.g., cutout replacement program to protect transformers and circuits)
  - Discrete investments address specific system needs based on asset health, safety, or reliability
- Regulators can scrutinize new programs and significant changes to existing asset management programs, practices, or system needs and corresponding changes to spending levels, compared to historical averages
  - Examine utility justification and data for each change, as well as cost impacts, anticipated benefits, and overall spending efficiency
- Regulators also can provide guidance to:
  - Target and prioritize investments by avoided risk (value-spend efficiency)
  - Balance risk avoidance with rate impacts to determine timelines
  - Identify opportunities to coordinate upgrades related to the same or adjacent infrastructure to reduce costs and avoid multiple outages
  - Identify reportable data to assess program impact and effectiveness

Example: MN PUC requirements for distribution planning data on asset health, age-related replacements, and asset renewal

Programmatic Investment to Replace Porcelain Cutouts



Source: Xcel Energy (MN) 2023 Integrated Distribution Plan