



A Strategic Framework for Utility Cost Control

How to Promote Cost-Efficiency Through the Energy Transition



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About RMI

RMI is an independent nonprofit, founded in 1982 as Rocky Mountain Institute, that transforms global energy systems through market-driven solutions to align with a 1.5°C future and secure a clean, prosperous, zero-carbon future for all. We work in the world's most critical geographies and engage businesses, policymakers, communities, and NGOs to identify and scale energy system interventions that will cut climate pollution at least 50 percent by 2030. RMI has offices in Basalt and Boulder, Colorado; New York City; Oakland, California; Washington, D.C.; Abuja, Nigeria; and Beijing.

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Executive Summary



The electric grid will require major investments in the coming years to address multiple challenges. These include accommodating accelerating load growth, modernizing the system, replacing aging assets, rapidly scaling down carbon emissions to meet state policy goals, and hardening the grid to withstand more severe wildfires, winter storms, hurricanes, and other impacts of the changing climate. Meeting these needs while ensuring utility service is affordable to customers is critical, but it will not be easy given the number of customers who already struggle to pay their utility bills.

The public utility commissions (PUCs) that oversee regulated utilities have four main avenues through which they can support affordability. The first is *cost control*, which means ensuring that the overall cost of service is no more than necessary. The second, *cost responsibility*, refers to how the overall cost is allocated among different groups of customers. The third avenue is *predictability*, which indicates how well customers can predict the size of their future bills so that they can be budgeted for. Last, the fourth avenue, *agency*, refers to how much influence customers have over their bills. Although all four of these avenues are important, this report focuses primarily on the first, cost control.

To help state regulators identify and implement appropriate reforms, we propose a strategic framework to clarify the range of options available to PUCs to support cost control (see Exhibit ES1). The framework is structured around seven strategies, and it includes 16 specific levers that can be used to operationalize the strategies. This framework can serve as a library of ideas that PUCs — as well as consumer advocates and other stakeholders — can draw from to design effective portfolios of reforms to promote cost control.

Exhibit ES1 A strategic framework for utility cost control



RMI Graphic

We present the details of the framework in a compact format designed to be both informative and practical. We first discuss the purpose of each strategy and then identify relevant levers that can be used by PUCs to apply it. For each lever, we provide a brief definition, explain how it can support cost control, and provide a few key tips for implementation. For readers who would like more information about a lever, we offer a short list of suggested resources for further reading.

Before we introduce the framework, we provide a brief discussion of key drivers of increasing costs in recent history and explore how these trends are likely to continue to affect future grid spending needs. The aim of this discussion is to ground the framework and assist state regulators and stakeholders in identifying the levers that best fit the needs of their jurisdictions.

Cost-efficient spending will be a key element in ensuring affordability in the coming years while meeting system needs and state policy goals. We hope this strategic framework for cost control will help regulators across the country successfully navigate the coming challenges.

Introduction

In the years ahead, billions of dollars of new investments in the electric sector will be needed to address pressing challenges. These include expanding the grid to accommodate accelerating load growth, modernizing it to incorporate advanced technologies, replacing carbon-intensive resources with clean alternatives, replacing many grid assets that are nearing the end of their useful lives, and increasing system resilience in the face of severe weather. The PUCs that oversee regulated utilities are tasked with ensuring that all these challenges are adequately addressed while electric service is provided at just and reasonable rates for customers.

Just and reasonable rates are intended to ensure that compensation for electric service is fair and that it reflects an appropriate balance between the interests of customers and those of utilities.ⁱ Affordability is an inherent part of this concept because it is important that rates are not excessively burdensome for customers. However, it can be challenging to maintain affordability while also providing utilities with sufficient revenue to maintain safe and reliable service and achieving local policy goals. Additionally, a growing number of states have mandated that PUCs evaluate utility services through an equity lens, ensuring fair access and service provision across different demographic groups.¹

Meeting all these objectives is a tall order, not least because many customers already struggle to pay their electric bills. According to the US Department of Energy (DOE), affordability means customers “should be able to pay for their home electricity use — lighting, heating, cooling, powering appliances — while also paying for other basic living expenses, such as food and medication, without having to choose or feel overburdened.”² However, in 2023, an estimated one in four households in the United States reported that they had to forgo necessary expenses to pay their energy bills.ⁱⁱ

Electricity is critical to human health and well-being, and when individuals are unable to access utility services, it has ripple effects on their communities and local economic activity.ⁱⁱⁱ Ensuring that electric rates are affordable to customers is therefore of prime importance on both individual and societal levels.

i PUCs have traditionally focused on key objectives such as ensuring safety and reliability. They regulate utilities to guarantee that customers receive dependable and safe electricity. In return, utilities are allowed to recover the costs of service and earn a rate of return authorized by the PUC. While maintaining their commitment to traditional regulatory goals, PUCs today are increasingly responsible for delivering against a broader set of regulatory objectives, such as resilience, energy equity, climate impacts, and other priorities, all while ensuring rates remain fair and reasonable. See Jessie Ciulla et al., *Purpose: Aligning PUC Mandates with a Clean Energy Future*, RMI, 2021, pp. 6–7, <https://rmi.org/insight/puc-modernization-issue-briefs/>.

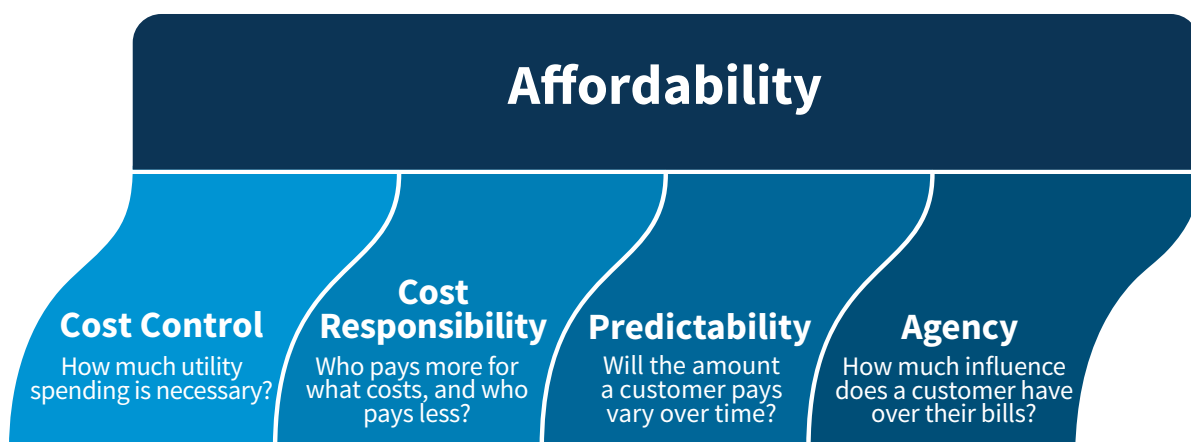
ii Nationally, customers whose income is 30% or less than that of the area median income pay on average 11% of their income for electricity, plus an additional 5% for gas and other sources of energy. This surpasses the 6% threshold that constitutes the level deemed unaffordable. This information was derived from the US DOE's Low-Income Energy Affordability Data (LEAD) tool, which was accessed in November 2024 but is no longer available at the time of publication. Individuals interested in the LEAD data can access it from the Open Energy Data Initiative, <https://data.openei.org/submissions/6219>. For the 2023 survey data, see “Week 63 Household Pulse Survey: October 18–October 30,” US Census Bureau, November 8, 2023, <https://www.census.gov/data/tables/2023/demo/hhp/hhp63.html>.

iii For a discussion of the impacts that losing access to electricity can have on customers and communities, see Docket No. 2022-0250, “Pathways to Disconnection Reform in Hawaii: Draft Memo prepared by RMI for the Hawaii Public Utilities Commission,” Hawaii PUC, <https://shareus11.springcm.com/Public/DownloadPdf/25256/3e5de332-905a-ef11-b848-48df377ee710/26d9dd86-a65a-ef11-b848-48df377ee710>.

PUCs have four main avenues available to support affordability. The first is *cost control*, which means ensuring that the overall cost of service is no more than necessary.^{iv} The second avenue is *cost responsibility*, which refers to how the overall cost is apportioned among different groups of customers. The third avenue is *predictability*, which concerns how well a customer can predict the size of their future bills. Predictability is particularly important for less financially secure customers, who may not have sufficient financial reserves to cover bills that are higher than expected. The fourth avenue, *agency*, refers to how much influence customers can exercise over the size of their bills. These four avenues are illustrated in Exhibit 1.^v

Exhibit 1

Four avenues through which PUCs can support affordability



RMI Graphic

Although all four of these avenues are important, this report focuses primarily on the first, cost control. To address the many challenges the grid faces while keeping rates affordable, ensuring that utilities spend money cost-efficiently will be critical.

However, the traditional regulatory framework — known as cost-of-service regulation — can create many perverse incentives that run counter to cost-efficiency. These perverse incentives, which include gold plating, capital expenditure (capex) bias, and the throughput incentive, encourage investor-owned utilities to spend *more*, not less, to increase their earnings.^{vi} These incentives, if unaddressed, would likely result in customer bills that are higher than necessary.

- ^{iv} Under the traditional cost-of-service model, capex becomes part of the utility's rate base (by which a rate of return is multiplied) and depreciated over time, while operating expenses are passed through quickly to customers. These components together determine the utility's revenue requirement, which forms the basis for setting customer rates. See Cara Goldenberg and Kaja Rebane, *How to Restructure Utility Incentives: The Four Pillars of Comprehensive Performance-Based Regulation*, RMI, 2024, pp. 13–14, https://rmi.org/wp-content/uploads/dlm_uploads/2024/07/RMI_how_to_restructure_utility_incentives.pdf.
- ^v The financial resources available to a customer are also an important factor in determining whether utility rates are affordable. However, PUCs typically have limited control over customer finances outside of the impact of utility rate structures and programs, such as compensation for grid services from customer-owned distributed energy resources.
- ^{vi} Gold plating refers to the incentive for an investor-owned utility to make more capital investments than necessary to increase its earnings — in other words, to “gold plate” its system. This perverse incentive can show up in different ways. Utilities might propose overly expensive projects, such as transmission upgrades instead of cost-effective grid-enhancing technologies; exaggerate demand forecasts to justify unnecessary infrastructure; avoid negotiating better prices with suppliers; or underutilize existing resources, such as demand response programs that could reduce peak loads. For more on these perverse incentives, see Rebane and Goldenberg, *How to Restructure Utility Incentives*, RMI, 2024.

The good news is that there are many regulatory levers PUCs can use to promote cost-efficiency. Some of these address the perverse incentives created by traditional cost-of-service regulation, while others focus on streamlining key planning processes or better leveraging the services of third parties to simulate competition and drive down cost.

In this report, we propose a strategic framework to clarify the range of options available to PUCs to support utility cost control (see Exhibit 2). The framework is structured around seven strategies, and it includes 16 specific levers that can be used to operationalize the strategies. This can serve as a library of ideas from which PUCs — as well as consumer advocates and other stakeholders — can draw. Since the 16 levers tackle the challenge of cost control in different and complementary ways, the framework can also be leveraged to design effective portfolios of reforms.

Exhibit 2

A strategic framework for utility cost control



We hope this strategic framework provides a useful guide for PUC action. However, it is not an exhaustive list of all the possible ways state regulators can promote better cost control, as it focuses on actions PUCs can take rather than on regional or federal reforms (e.g., improved oversight of transmission planning by regional transmission organizations, federal legislation). Also, it focuses on utility cost control to reduce the burden on utility ratepayers rather than on other means of reducing this burden, such as securing additional funding to supplement the revenues collected from ratepayers.^{vii} For these reasons, we encourage PUCs and other stakeholders to treat this framework as a useful tool and to also consider other options available to achieve their desired goals.

Although addressing cost control from a total system perspective supports affordability for all ratepayers, utility cost control alone is insufficient to adequately protect energy-burdened customers and safeguard their access to energy services. PUCs should therefore also adopt solutions specifically tailored to financially challenged customers. Such solutions — which address the other three avenues through which PUCs can support affordability — merit dedicated frameworks of their own.

The remainder of this report is structured as follows. First, we provide an overview of some of the key drivers of increased utility spending, both those that have contributed to cost increases in recent years and those expected to play larger roles in the future. Next, we introduce the strategic framework for cost control and provide additional information about each strategy and lever within it. Although the discussion of each lever is intentionally focused and brief, we identify key resources where interested readers can find more information.

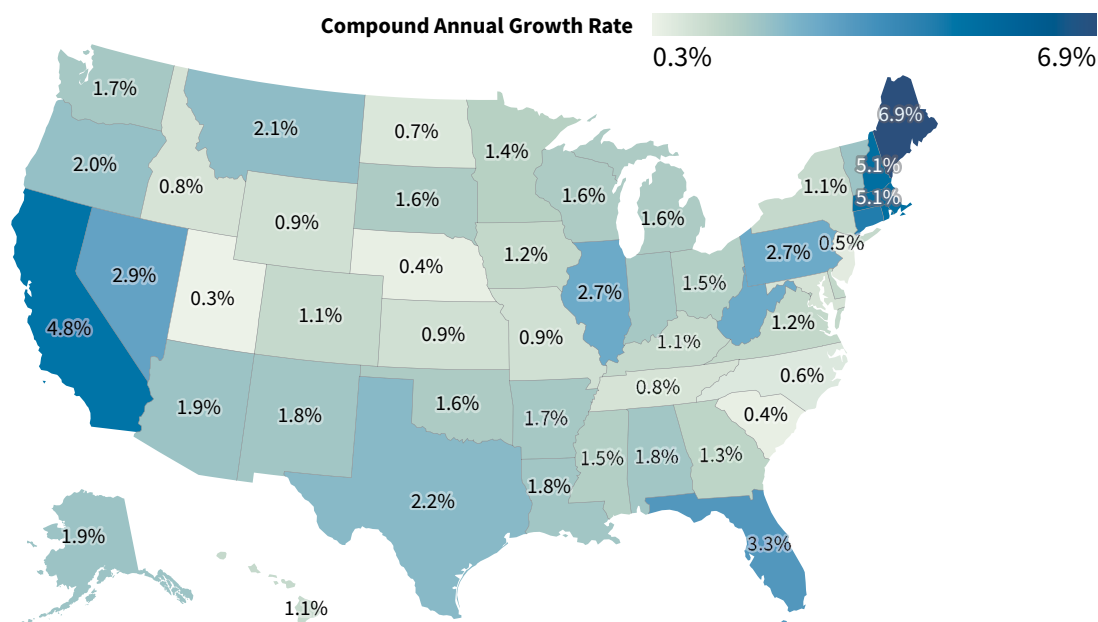
vii For example, the federal government has provided several funding opportunities for utilities to modernize their infrastructure and make new investments in clean energy. PUCs can direct utilities to consider grants, rebates, and other federal funding opportunities that could help lower the cost to customers. For more information, see Katerina Stephan et al., *Planning to Harness the Inflation Reduction Act*, RMI, 2024, <https://rmi.org/insight/planning-to-harness-the-inflation-reduction-act/>.

Key Drivers of Increased Utility Spending

To take a strategic approach to implementing cost-control reforms, it is helpful to begin with an understanding of the factors driving utility cost increases. This understanding includes both what has occurred in the recent past and — even more importantly — what is likely to happen in the future.

In recent years, customer bills have generally risen at roughly the rate of inflation.^{viii} However, the financial burden on many customers has increased as wages have lagged behind inflation.³ Furthermore, in some states, bill increases have exceeded the national average (see Exhibit 3), and the financial burden has grown heavier on certain already disadvantaged populations.^{ix} In several New England states, Florida, and California, electricity bills have risen fastest. From 2013 to 2023, electricity bills in these states increased by more than 3%, with Maine experiencing a particularly sharp rise of nearly 7%.

Exhibit 3 Average monthly residential electricity bill increases



Note: This map shows the compound annual growth rate of residential electric bills between 2013 and 2023 by state. The percentages shown are not adjusted for inflation, which was 3.1% over this period for the US.

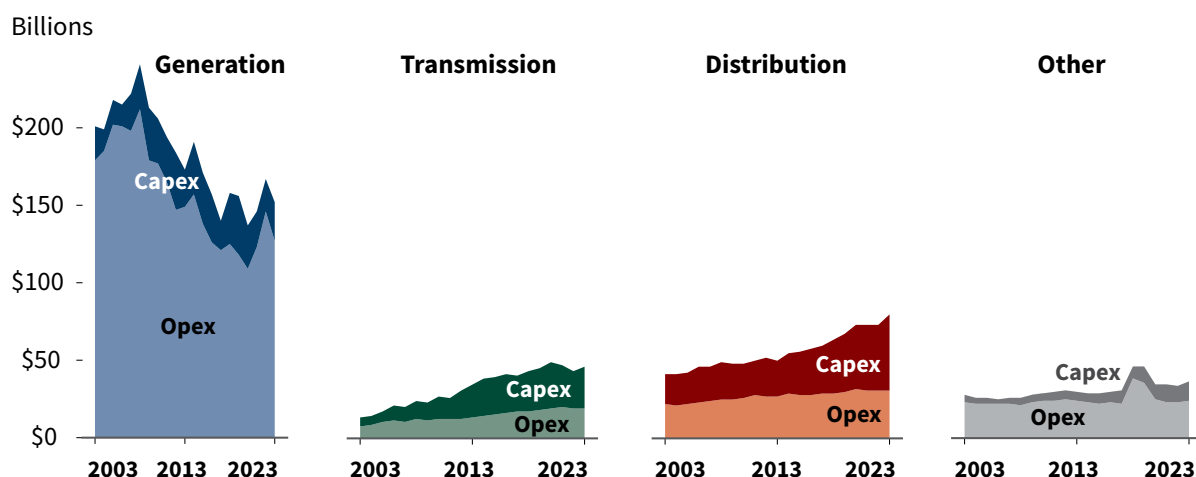
RMI Graphic. Source: EIA, https://www.eia.gov/electricity/sales_revenue_price/, and US Bureau of Labor Statistics, <https://www.bls.gov/data/tools.htm>

^{viii} Over the past decade, average residential electricity bills in the United States have increased at approximately the rate of inflation, rising by less than 1% in real terms from 2013 to 2023. See “Retail Electricity Prices Closely Tracked Inflation over the last 10 years,” US Energy Information Administration (EIA), September 11, 2024, <https://www.eia.gov/todayinenergy/detail.php?id=63064>.

^{ix} A Massachusetts Institute of Technology study found that energy burden increased substantially from 2015 to 2020 in areas with high concentrations of energy poverty, such as the Southeast and Southwest. See Carlos Batlle et al., “US Federal Resource Allocations Are Inconsistent with Concentrations of Energy Poverty,” *Science Advances* 10, no. 41 (October 9, 2024), <https://doi.org/10.1126/sciadv.adp8183>.

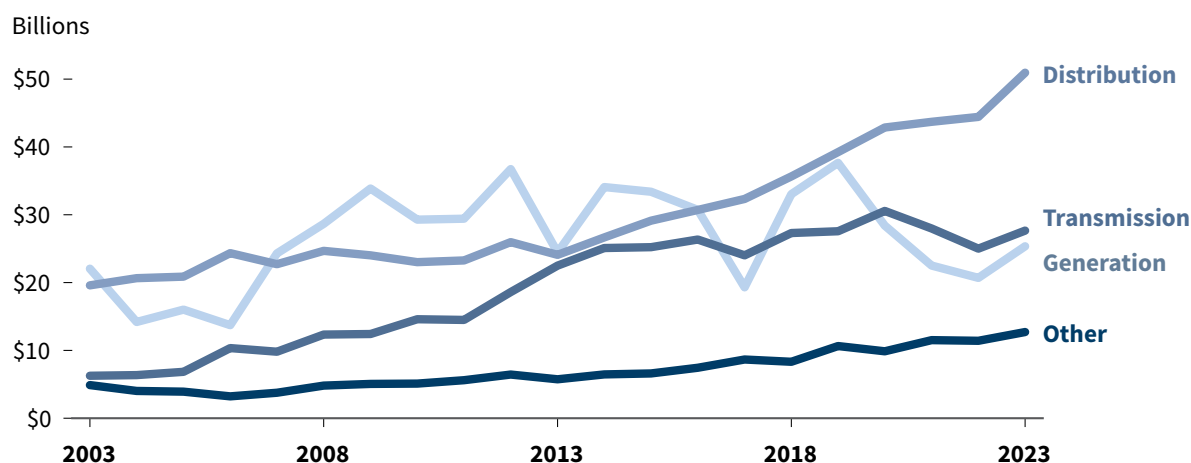
In part, rising bills can be attributed to increased spending on infrastructure. Although generation represents the largest spending category, its trajectory has generally declined (see Exhibit 4). In contrast, spending on transmission and distribution (T&D) as a share of total spending grew from roughly 20% to 40% between 2003 and 2023. These increases were largely driven by increased capex (see Exhibit 5). Transmission capital investment nearly doubled while distribution capital investment grew by 160%.

Exhibit 4 US electric utility spending trend by spending category



Note: Capex refers to capital expenditure and opex refers to operating expenses. Data shown in 2023 dollars.
RMI Graphic. Source: EIA, <https://www.eia.gov/todayinenergy/detail.php?id=63724#>

Exhibit 5 US Electric Utility Capital Investment by Spending Category



Note: Data shown in 2023 dollars.
RMI Graphic. Source: EIA, <https://www.eia.gov/todayinenergy/detail.php?id=63724#>

There are good reasons to believe the future will require even more spending than the recent past. Major structural shifts in society — such as projected load growth from data centers, reshoring of US manufacturing, and electrification — are already spurring new generation, transmission, and distribution projects. Meanwhile, the accelerating impacts of climate change are challenging grid resilience, which means utilities must take steps to harden infrastructure and improve emergency preparedness. Together, these trends are likely to increase the need for investment in future years. At the same time, supply-side challenges, such as interconnection delays, are also contributing to rising costs. These inflationary pressures have pushed many utilities to file for rate cases reflecting these higher costs.

Below, we explore a variety of factors that are contributing to utility cost increases: T&D investments, increasing reliance on natural gas for electricity generation, extreme weather and wildfires, and the slow adoption of new technologies. The relative strength of these cost drivers to date varies across the country.

Transmission and Distribution Investments

The increase in utility capital additions over the last two decades will have bill impacts for years to come. Because these represent investments in new assets that are typically depreciated over decades — with the costs recovered from customers over that same extended period — this increase in spending is only partly reflected in current customer bills. As demonstrated in Exhibit 5, much of the capital growth has been driven by T&D.^x

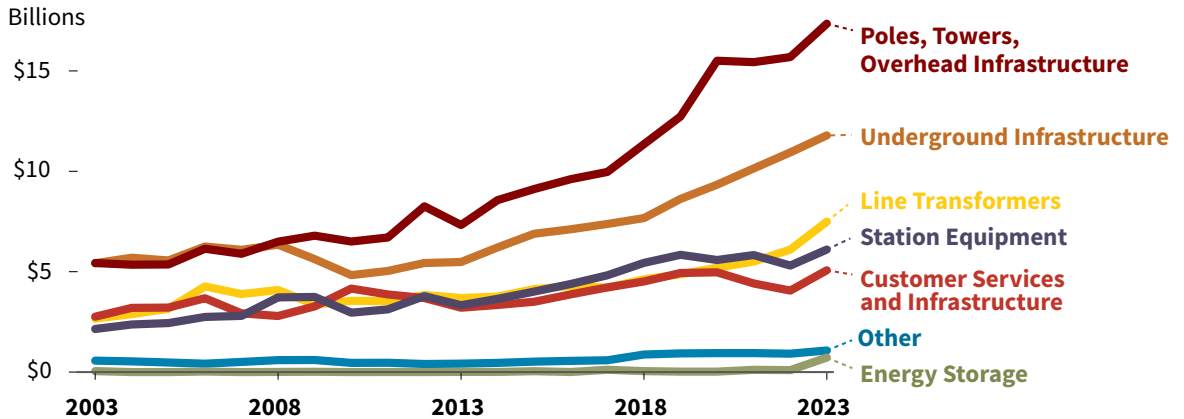
This increase in T&D spending is attributable to several factors. One major contributor has been the need to replace aging assets nearing the end of their useful lives.⁴ Other contributors have included the need to modernize the grid to take advantage of new technologies (e.g., advanced metering infrastructure) and to harden the system to withstand increasingly severe weather and wildfires. Global supply chain challenges, inflation, and labor costs have also increased the prices of key equipment, such as transformers and other electrical components.⁵

As shown in Exhibit 6, not all categories of distribution system investment have grown at the same rate over the past two decades. Overhead infrastructure and underground lines saw the largest increases, which partly reflect utility efforts to address outages and improve reliability. Spending on line transformers rose by 180% from 2003 to 2023, due in part to supply chain challenges. Although still a tiny part of the total budget, energy storage spending surged from \$97 million in 2022 to \$723 million in 2023, reflecting its growing role in stabilizing grids with variable renewable resources.

x A contributing factor to this trend is the increasing reliance on independent power producers to supply generation. Power purchase agreements and other forms of purchased power are considered operating costs, so generation continues to shrink as a share of overall capital spending. For more detail, see “Major US Utilities Spending More on Electricity Delivery, Less on Power Production,” EIA, November 23, 2021, <https://www.eia.gov/todayinenergy/detail.php?id=50456>.

Exhibit 6

Annual utility capital investment in distribution



Note: Data shown in 2023 dollars.

RMI Graphic. Source: EIA, <https://www.eia.gov/todayinenergy/detail.php?id=63724#>

On the transmission system, recent cost increases reflect a shift from larger, higher-voltage projects to smaller projects built on the local scale by individual utilities. This shift can be attributed to a regulatory gap in transmission planning, which discourages utilities from leveraging regional planning processes to expand transmission capacity in a cost-effective manner. Nationally, 90% of recent transmission spending has been on lower-voltage reliability upgrades. In certain regions, such as the Mid-Atlantic and New England, the proportion of spending on local projects has skyrocketed. This trend has ultimately raised costs for consumers without effectively enhancing system resilience or accommodating new generation.^{xi}

T&D costs are expected to continue to increase, with one recent survey indicating that utilities expect future T&D investments to be split fairly equally between the replacement of existing assets, the addition of new assets to expand the grid, and investments focused on hardening the system to be more resilient and incorporating advanced technologies (see Exhibit 7). Notably, in the transmission sphere, grid expansion is projected to account for 44% of future investment.^{xii} Given that almost half of future transmission spending is expected to focus on expansion, regional planning could provide a significant opportunity to optimize these costs through better planning and coordination.^{xiii}

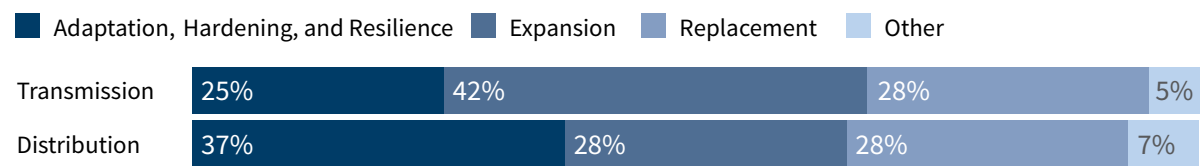
xi There are key reforms that could close the regulatory gap in transmission planning, including both regional and state-level strategies. By implementing regional-first planning and reforming federal oversight, regulators could redirect investment toward higher-voltage, more impactful projects, allowing a more proactive approach to grid planning and cost control. For more details, see Claire Wayner, Kaja Rebane, and Chaz Teplin, *Mind the Regulatory Gap: How to Enhance Local Transmission Oversight*, RMI, 2024, <https://rmi.org/insight/mind-the-regulatory-gap/>.

xii If designed properly, transmission investments that increase access to low-cost resources can lead to production, capacity, and overall system cost savings, as these investments are offset by avoided costs in other areas.

xiii Order No. 1920, issued by the Federal Energy Regulatory Commission (FERC), aims to address some of these inefficiencies by enhancing the transparency and regional integration of local projects. For example, the rightsizing provision encourages utilities to consider whether larger regional projects could be more cost-effective compared with smaller local efforts. Focusing on how these spending categories align with the regulatory improvements introduced by Order No. 1920 will be crucial for state regulators and utilities as they work to ensure a resilient, future-ready grid without placing unnecessary cost burdens on consumers. For more, see “Explainer on the Transmission Planning and Cost Allocation Final Rule,” FERC, September 25, 2024, <https://www.ferc.gov/explainer-transmission-planning-and-cost-allocation-final-rule>; and Wayner, Rebane, and Teplin, *Mind the Regulatory Gap*, RMI, 2024.

Exhibit 7

Breakdown of expected future T&D investments by US utilities



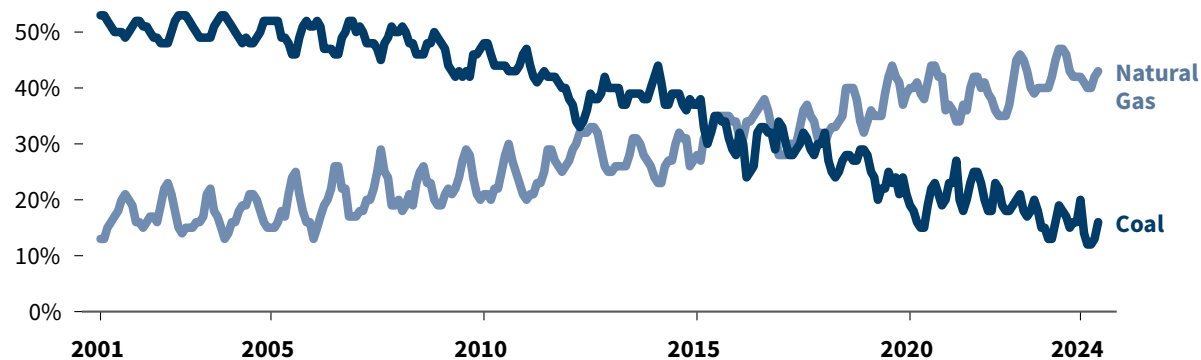
RMI Graphic. Source: Edison Electric Institute, <https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Finance-And-Tax/Industry-Capital-Expenditures.pdf>

Reliance on Natural Gas

Since 2009, the cost of electricity generation has decreased and remained relatively stable, partially due to the decreasing costs associated with renewable energy sources.⁶ During this period, coal use declined significantly while reliance on natural gas for power generation continuously increased (see Exhibit 8).⁷

Exhibit 8

Percentages of natural gas and coal in US electricity generation



RMI Graphic. Source: EIA, <https://www.eia.gov/electricity/monthly/>

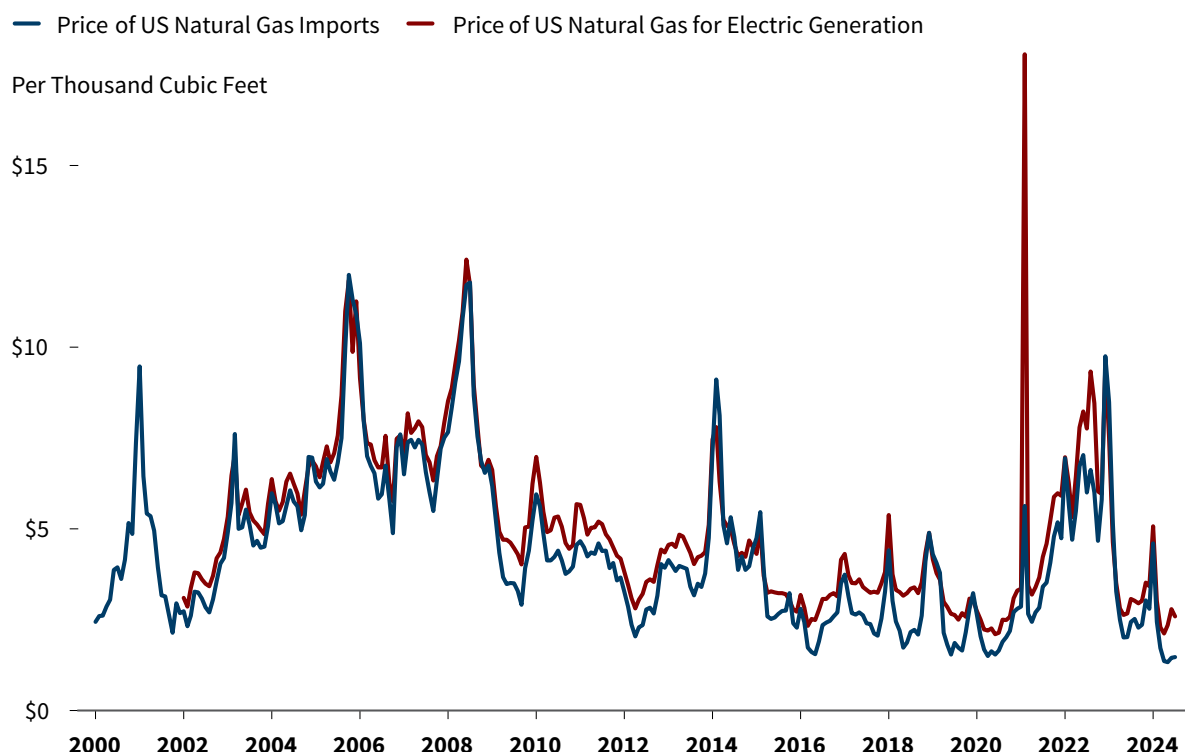
The growing reliance on natural gas introduces new challenges, particularly due to its inherent price volatility. Unlike renewables, which have no fuel costs, natural gas prices can fluctuate dramatically. When demand is high or supply is constrained, customers may face significant costs if their utility relies heavily on natural gas.^{xiv} For example, a severe winter storm in 2021 caused natural gas demand to surge in many

xiv For instance, a recent analysis in North Carolina found that since 2017, increases in natural gas fuel costs accounted for 67% of residential rate increases in the Duke Energy Carolinas territory and 46% in the Duke Energy Progress territory. Reliance on natural gas generation exposes customers to significant rate volatility, which in most contexts is entirely borne by ratepayers rather than utility shareholders. For more, see Julie Murphy, “New Analysis Shows Reliance on Gas Is Primary Driver of Rise in Duke Energy Power Bills,” Environmental Defense Fund, April 18, 2024, <https://www.edf.org/media/new-analysis-shows-reliance-gas-primary-driver-rise-duke-energy-power-bills>.

states and notably constrained gas supply in Texas.^{xv} Soon after, Russia’s invasion of Ukraine cut off a large portion of the global supply of natural gas. As shown in Exhibit 9, the increased demand and supply disruptions led to surges in spot prices in 2021 and 2022, which peaked at levels not seen in more than a decade.

Exhibit 9

Price of US natural gas: Imports and electric generation



Note: Price presented in nominal dollars.

RMI Graphic. Source: EIA, <https://www.eia.gov/naturalgas/monthly/>

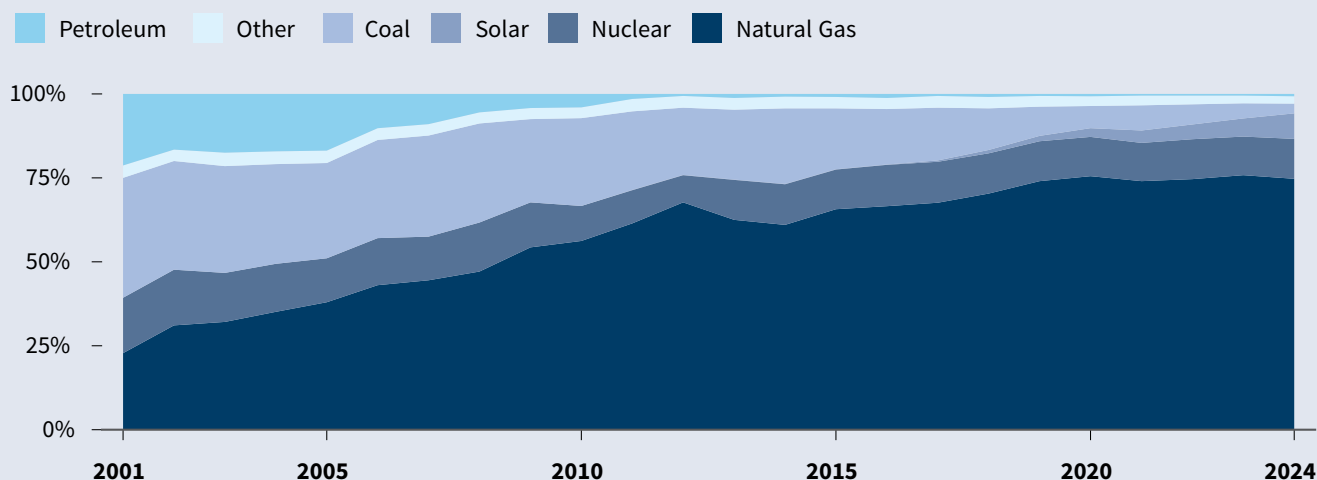
The combination of increased reliance on natural gas and its price volatility will likely continue to pose a challenge to affordability in future years. In addition, to meet state climate goals, some natural gas assets will need to be retired before the end of their originally anticipated useful lives. If customers are required to pay off the undepreciated balance of these stranded assets, this will pose an additional challenge to affordability.

xv On February 17, 2021, Texas’s daily natural gas production encountered a temporary decrease of approximately 50%, based on estimates from IHS Markit. This decline was attributed to well freeze-offs resulting from the freezing of water in the raw natural gas stream. For details, see Owen Comstock, “US Natural Gas Prices Spiked in February 2021, Then Generally Increased through October,” EIA, January 6, 2022, <https://www.eia.gov/todayinenergy/detail.php?id=50778>.

Case Study: The impact of natural gas reliance on electricity prices in Florida

Florida's energy landscape has undergone significant changes over the past two decades, with a large and growing dependence on natural gas for electricity production as coal generation has declined. Although this transition has yielded some benefits, such as lower emissions and initial cost savings compared with continuing to rely on coal, it has also increased the state's exposure to fuel-price risk and raised concerns about long-term affordability.⁸ As of 2023, natural gas accounted for approximately 76% of Florida's net electricity generation, more than triple its share in the early 2000s. Florida's increasing reliance on natural gas for power production is illustrated in Exhibit 10.

Exhibit 10 Percentage of electricity generation in Florida by resource



Note: The data for the years 2023 and 2024 is preliminary and subject to change.
RMI Graphic. Source: EIA, <https://www.eia.gov/state/analysis.php?sid=FL>

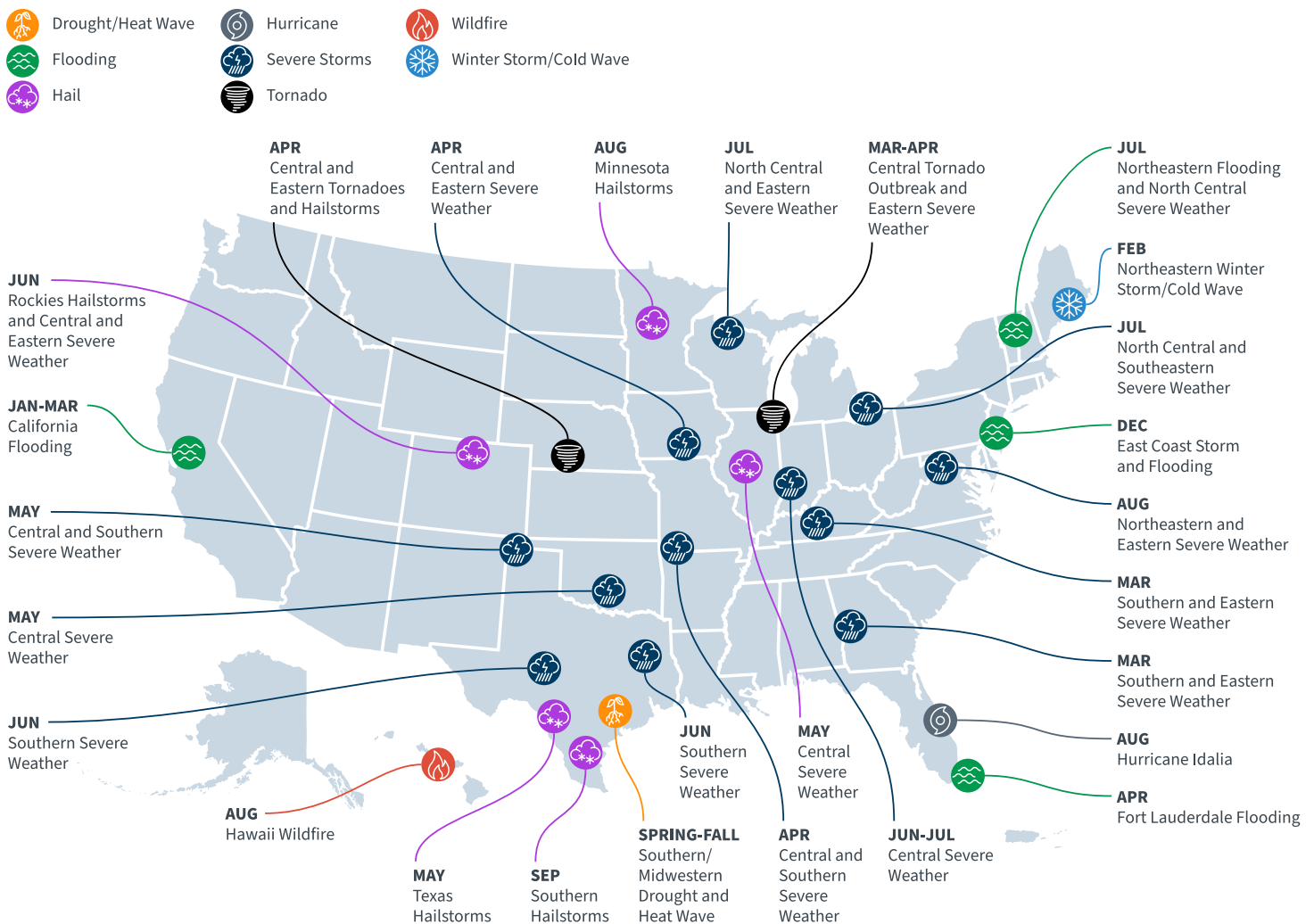
Due to the heavy reliance of Florida's utilities on natural gas, ratepayers were severely affected by the 2021 price surge caused by Winter Storm Uri in Texas. Florida Power & Light Company, the state's largest utility, filed a midcourse correction petition with the Florida Public Service Commission to adjust its 2021 fuel-cost recovery factors. In the proceeding, the utility requested a true-up of \$230 million in fuel costs from customers in the year 2021.^{xvi} Similarly, Duke Energy Florida sought approval to adjust its 2021 fuel-cost recovery factors by \$190 million, citing higher natural gas prices.⁹ In both cases, the petitions were approved, and consumers had to bear the full brunt of this fuel-price spike through rate adjustments. As a result, Florida Power & Light residential customers saw an 18% increase to their electricity bills from May to December 2021, and Duke Energy residential customers faced a 15% bill hike from September to December 2021.

^{xvi} A midcourse correction is used by the Florida Public Service Commission between annual fuel clause hearings when costs deviate from allowed revenue by a significant margin. A utility must notify the commission whenever it expects to experience an under- or over-recovery greater than 10%. For details, see Docket No. 20210001-EI, "Order No. PSC-2021-0142-PCO-EI Order Approving Florida Power & Light Company's Petition For Mid-Course Correction," Florida Public Service Commission, April 21, 2021, <https://www.psc.state.fl.us/library/filings/2021/03605-2021/03605-2021.pdf>.

Extreme Weather and Wildfires

In recent years, extreme weather intensified by climate change has significantly driven up costs for electricity consumers. As states experience more frequent wildfires, heat waves, droughts, and coastal flooding, utility regulators are facing increasing pressure to balance the need for cost control with the imperative of enhancing grid resilience. The frequency and intensity of extreme weather events triggered by climate change continue to increase, and economic losses have already amounted to tens of billions of dollars annually.¹⁰ Exhibit 11 shows the billion-dollar disasters in 2023 alone.

Exhibit 11 Billion-dollar weather and climate disasters in 2023



Note: This map displays climate disasters across the United States in 2023, each resulting in over \$1 billion in damages. These high-impact events, including hurricanes and wildfires, underscore the increasing financial strain on the nation's electric system due to extreme weather

RMI Graphic. Source: National Oceanic and Atmospheric Administration, <https://www.climate.gov/news-features/blogs/beyond-data/2023-historic-year-us-billion-dollar-weather-and-climate-disasters>

Hurricanes, for instance, have caused widespread power outages and damage to infrastructure, especially in coastal states. For example, Hurricane Ian in 2022 caused \$113 billion in damage, disrupting Florida’s grid and leading to extensive restoration costs for utilities.¹¹

Unlike hurricanes or other extreme weather, which utilities cannot prevent, wildfires not only threaten utility equipment but can also be triggered by that equipment.^{xvii} As such, utility wildfire costs can also include damage payouts and liability insurance — and the total financial impact can be massive.

Over the past 23 years, 273 major power outages in the West have been attributed to wildfires.¹² Pacific Gas & Electric (PG&E), one of California’s largest investor-owned utilities, has spent billions of dollars upgrading its grid and paying damages from fire-related lawsuits, which has significantly increased electricity rates in the state.¹³ Across California, wildfire costs, including mitigation, insurance, and damage, have driven a cumulative \$5.5 billion increase in revenue requirements, accounting for roughly 16% of California’s utility revenues in 2022.¹⁴

The heavy financial burden of recent wildfires has sparked debate about the appropriate allocation of wildfire costs.¹⁵ Some stakeholders have also raised concerns that mitigating wildfire risk has become an opportunity for increased utility spending subject to limited prudence review, which could pad utilities’ earnings and reduce their liability exposure while unnecessarily increasing costs for customers.¹⁶



xvii The 2023 Maui wildfire demonstrates the risks associated with utility equipment. The fire was caused by downed power lines that were reenergized manually after utility personnel conducted a visual inspection and deemed the line to be up and intact. This caused the ejection of sparks, igniting the unmaintained vegetation below. For more detail, see Steve Kerber and Derek Alkonis, *Lahaina Fire Incident Analysis Report*, UL Research Institutes, 2023, <https://doi.org/10.60752/102376.26858962>.

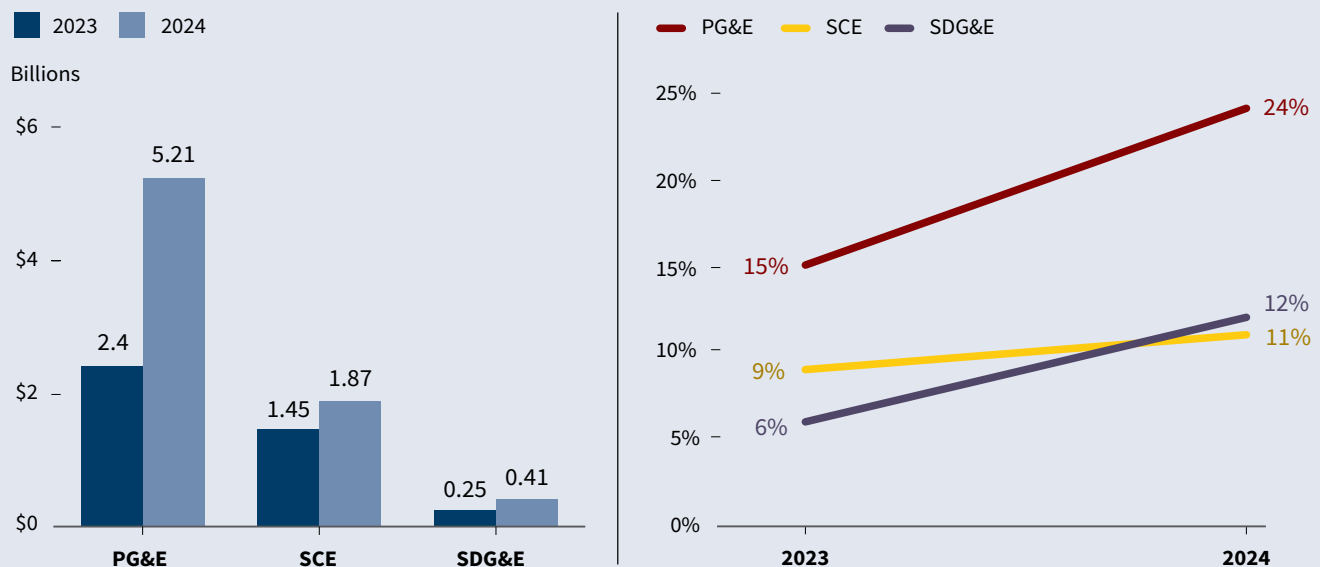
Case Study: The impact of wildfires on utility costs in California

Wildfires have become the most destructive and costly climate event in California. Over the past decade, prolonged droughts and higher temperatures have made California's vegetation drier, contributing to more severe and frequent fires. These wildfires have not only caused widespread damage to infrastructure but have also led to billions of dollars in costs for grid upgrades, emergency response, and legal liabilities for utilities.

The state's three major investor-owned utilities, PG&E, Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E), have recently faced considerable increases in wildfire-related costs. These costs encompass wildfire mitigation efforts, restoration after disasters, and settlements paid to those affected by utility-caused wildfires. For example, as part of an effort to make proactive investments in wildfire risk reduction, the California Public Utilities Commission approved a plan for PG&E to bury 1,230 miles of electric lines and install 778 miles of covered conductor. The cost of these investments contributed to an 11% increase in PG&E's revenue requirement in 2023 relative to 2022.¹⁷

Between 2023 and 2024, PG&E experienced a 117% increase in wildfire-related costs (from \$2.4 billion to \$5.2 billion), representing 24% of PG&E's total revenue requirement in 2024. Similarly, SDG&E's and SCE's wildfire-related costs rose 94% and 29%, respectively, and accounted for 12% and 11% of their total revenue requirements in 2024 (see Exhibit 12). This increased spending is expected to continue.

Exhibit 12 Wildfire-related revenue requirements by utility



Note: The bars illustrate the cost of wildfire-related revenue requirements of each of the state's three largest utilities. The percentages indicate the share of the utility's total revenue requirements that these wildfire-related costs represent.

RMI Graphic. Source: California Public Advocates Office, <https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/240613-public-advocates-office-electric-iou-wildfire-cost-increases.pdf>, and <https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/240722-public-advocates-office-q2-2024-electric-rates-report.pdf>

Slow Adoption of Cost-Saving Technologies

Another recent development is that electricity demand, which remained relatively flat for decades, has begun to climb.^{xviii} One factor contributing to this is demand from data centers, a relatively new phenomenon powered largely by recent developments in artificial intelligence and related technologies. Although this has not yet had a large effect, projected loads for data centers could pose challenges to the grid going forward.^{xix} Another factor is customer adoption of electric vehicles, heat pumps, and other electrified end uses. So far, electrification has not dramatically increased electricity usage, but in the coming years, its impact is also likely to grow substantially.¹⁸

Luckily, the adoption of clean energy technologies has also been accelerating in recent years. Although partly driven by state climate policies, this trend is primarily a response to the decreasing costs of renewable generation, energy storage, and other clean technologies. Evidence suggests that the shift toward clean technologies has not been driving recent utility cost increases because these resources are usually adopted because of their favorable economics — not in spite of them.^{xx}

However, to meet forecasted load growth while decarbonizing the electric grid — as an increasing number of states have committed to do within a few decades — much greater investment in clean technologies and in expanding grid capacity will be needed. To limit future cost increases from this resource build-out, cost-efficient spending decisions will be important. Compounding these challenges is the traditional cost-of-service business model for investor-owned utilities, which encourages them to prefer capital investments over other alternatives. This is because under the traditional business model, investor-owned utilities are allowed to earn a rate of return on their capex, whereas operating expenses (opex) generally do not offer the utility a profit opportunity. Since utilities' authorized return on equity (ROE) is typically set higher than their true cost of equity in the United States, utilities are incentivized to prioritize capital investments over operational solutions even when the latter are more cost-effective. This perverse incentive is called capex bias.¹⁹

As shown in Exhibit 13, over the past decade, authorized ROEs for investor-owned utilities in the United States have remained relatively high and stable, despite fluctuations in broader market indicators. For

xviii Total US retail electricity sales grew modestly between 2019 and 2023, by an average annual growth rate of 0.4%. However, this overall stability masks significant variations at the state and utility levels. Seven states saw load growth exceeding 2% annually. For more detail, see Sydney Forrester et al., *Retail Electricity Price and Cost Trends: 2024 Update*, Lawrence Berkeley National Laboratory, 2024, <https://emp.lbl.gov/publications/retail-electricity-price-and-cost>. Demand growth can reduce rates by spreading a utility's revenue requirement across a larger volume of sales, effectively lowering the cost per kWh, but this does not necessarily improve affordability from a whole-bill perspective. In fact, demand growth can have the opposite effect over the long term because sustained increases in load require further capital investments. These new investments will then raise customer bills for years to come due to the delayed impact of depreciation.

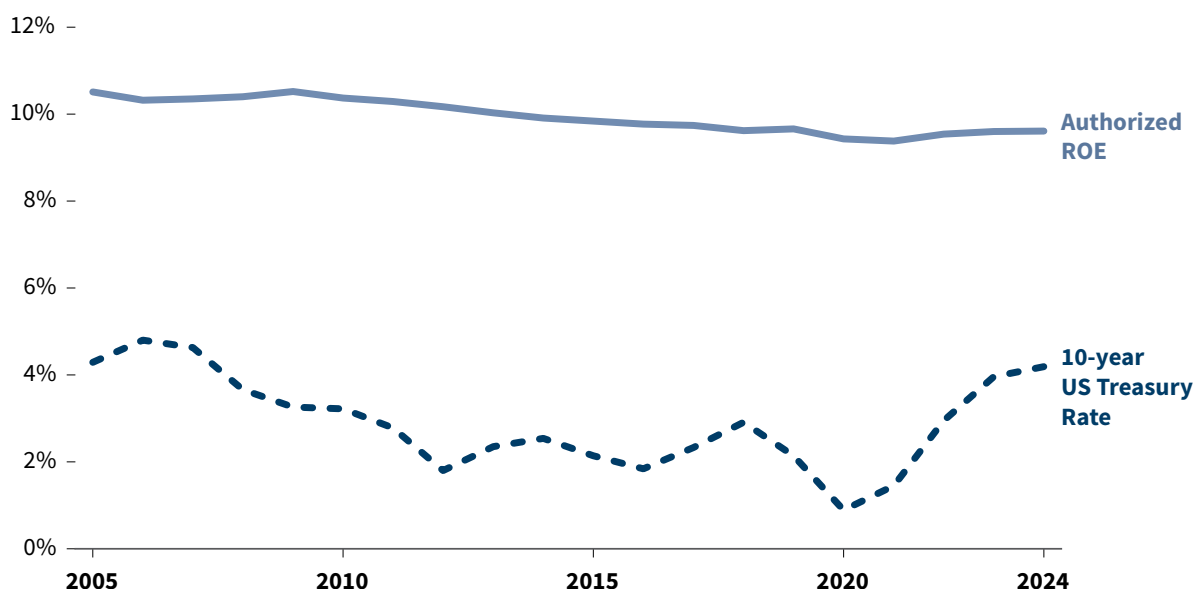
xix For example, in North Dakota, data centers drove 7% annual growth in retail electricity sales between 2019 and 2023, and several utilities in states including Oregon, Florida, Texas, and Virginia experienced growth in excess of 10% over the same time period (see Forrester et al., *Retail Electricity Price and Cost Trends*, 2024). Load growth from data-center expansion and the rise of artificial intelligence applications could pose major challenges to the grid going forward, though it could also support decarbonization efforts if managed appropriately. For an extended discussion of managing electricity load growth without compromising climate goals, see Mark Dyson and Lauren Shwisberg, *Reality Check: Electricity Load Growth Does Not Have to Undermine Climate Goals*, RMI, 2024, <https://rmi.org/reality-check-electricity-load-growth-does-not-have-to-undermine-climate-goals/>.

xx Clean energy technologies are projected to continue decreasing in cost, which could allow for significant emissions reductions in the electricity sector without driving up customer bills. Analysts predict further cost declines for solar, wind, and energy storage between 2024 and 2030, enabling the grid to achieve high levels of carbon-free electricity without raising rates. See Brendan Pierpont, *Clean Energy Isn't Driving Power Price Spikes*, Energy Innovation, 2024, <https://energyinnovation.org/wp-content/uploads/2024/07/Clean-Energy-Isnt-Driving-Power-Price-Spikes.pdf>.

example, during the COVID-19 pandemic, the 10-year US Treasury rate dropped sharply to 0.9% in 2020 before rebounding to 4.2% in 2024, yet authorized ROEs for electric utilities only decreased slightly, from 9.7% to 9.4%.^{xxi} In addition, compared with other capital-intensive industries, such as oil and gas distribution and real estate, utility ROEs appear insulated from market conditions, which further suggests that utilities continue to receive returns that may exceed what is necessary to attract investment.²⁰

Exhibit 13

Authorized ROEs for US electric utilities



RMI Graphic. Source: S&P, <https://www.capitaliq.spglobal.com/web/client?auth=inherit#industry/statisticsAndGraphs>, and Federal Reserve Bank, <https://fred.stlouisfed.org/series/DGS10#0>

Since the traditional utility business model bases a utility's earnings on the size of its capital investments, utilities operating under it could be expected to not aggressively pursue cost-saving opportunities. This is precisely what is observed in practice. In general, US utilities have been slow to deploy and utilize technological advances that could reduce the necessity for capital investment and hence lower costs for customers. For example, fully deploying grid-enhancing technologies (GETs) on the transmission system could generate huge savings for customers, yet GETs remain rare in the United States.^{xxii} Other examples of technologies that utilities have been slow to deploy include third-party-operated virtual power plants (VPPs)

xxi The 10-year US Treasury rate is used as a benchmark because it reflects broader market conditions and investor expectations for risk-free returns over a significant time horizon. Comparing authorized ROEs for utilities against this rate helps assess whether the returns granted to utilities align with market trends and the cost of capital in the economy.

xxii According to recent RMI research, deploying GETs in the PJM Interconnection could enable 6.6 gigawatts of new solar, wind, and storage projects to interconnect by 2027 and yield approximately \$1 billion annually in production cost savings. For details, see Katie Mulvaney et al., *GETting Interconnected in PJM*, RMI, 2024, <https://rmi.org/insight/analyzing-gets-as-a-tool-for-increasing-interconnection-throughput-from-pjms-queue/>.



and opex-based solutions to leverage advanced meters (many utilities have adopted the meters themselves, which offer them an earnings opportunity, but have been slow to deploy the additional systems needed to leverage those meters in ways that provide grid benefits).^{xxiii} Utilities' lack of engagement with these technologies is likely due, at least in part, to the incentives they face under the traditional cost-of-service regulatory framework.^{xxiv}

Another example of this dynamic is utilities' continued investment in coal. Many utilities continue to invest capital into aging coal plants, even as they become increasingly uneconomic. The book value of coal and steam gas assets has more than doubled since 2005 — from \$42 billion then to nearly \$96 billion in 2024 — despite a 16% reduction in the installed capacity.²¹ Even though fossil assets can become increasingly costly to maintain and to keep in compliance with regulations as they age, the discrepancy between the money invested and the capacity available to serve customers suggests that investments in other, more cost-effective technologies are potentially being overlooked in favor of maintaining these costly assets.

Although the impacts of the incentives created by the traditional regulatory model are difficult to measure precisely, they may influence all aspects of utility decision-making, including planning, investment, and daily operations. While the existence of perverse incentives is not new, they pose particular problems for regulators today who are tasked with ensuring that grid investment needs are met in a manner affordable for customers.

xxiii For insights into the challenges of scaling VPP adoption, the need for advancing best practices, and policy shifts to establish a sustainable VPP market in the coming years, see Kevin Brehm et al., *Virtual Power Plants, Real Benefits*, RMI, 2023, <https://rmi.org/insight/virtual-power-plants-real-benefits/>.

xxiv For more on the incentives created by the existing regulatory model and the impacts they can have on utility uptake of GETs and other key technologies, see Rebane and Goldenberg, *How to Restructure Utility Incentives*, RMI, 2024.

Case Study: The use of cost trackers for capital expenses in Virginia

A cost tracker is a ratemaking mechanism designed to collect revenues from customers to precisely recover a utility's actual expenditures in specific areas, in contrast to the traditional regulatory approach of setting rates on a forward-looking basis based on the utility's expected spending needs. Cost trackers can erode the utility's incentive to make cost-efficient spending decisions, and when applied to capital costs, they can exacerbate the perverse incentive to overinvest in capital assets.

The use of cost trackers to recover utility expenditures in the United States has expanded substantially over the past few decades. In 2022, roughly 81% of investor-owned utilities in the United States used cost trackers for fuel and purchased power, 70% used them for energy-efficiency programs, 50% used them for transmission-related expenses, 28% used them for environmental compliance costs, 23% used them for renewables expenses, and 13% used them for generation capacity costs.²²

Virginia's investor-owned utilities, Dominion Energy Virginia (DEV) and Appalachian Power Company (APCo), are prime examples of this trend toward increased use of cost trackers. Both utilities are allowed by state statute to recover certain costs through cost trackers (which are referred to as rate adjustment clauses, or RACs, in Virginia). RACs were authorized by legislation in 2007 for a variety of expenses, including energy-efficiency program expenses, costs to comply with environmental laws and regulations (including the state's renewable portfolio standard), generation projects, transmission costs, and various distribution system costs.²³ Since their authorization, RACs have grown to represent an average of 22% of a typical DEV residential bill (i.e., 1,000 kilowatt-hours [kWh] per month) between 2021 and 2023, and 30% for APCo during the same period.²⁴

Dominion Energy, the parent company of DEV, has communicated expectations to investors of \$27.9 billion of capex growth between 2022 and 2026, of which 92% is eligible to be recovered through RACs.²⁵ The quick recovery of tracked costs substantially lowers the financial risk to utility investors. However, Virginia state law prohibits the regulator from lowering the utility's authorized ROE below the average of a peer group of vertically integrated utilities operating in the Southeast United States.²⁶ This means that unless the authorized ROEs of utilities within the peer group were set at a level consistent with the reduced risk from the use of RACs in Virginia, the commission is essentially barred from authorizing a risk-appropriate ROE for Virginia's utilities. Because utility overearnings are funded by ratepayers, this policy poses a challenge to affordability in Virginia.

Anticipating future trends will be key to meeting grid needs in a cost-efficient manner, but it is also important to expect the unexpected. For example, the recent boom in artificial intelligence and data center construction that is driving surging demand forecasts today was not even on most regulators' radar a couple of years ago. As technological change accelerates, new solutions may become available to reduce grid costs in ways we cannot even imagine today. Regulatory reforms that enable PUCs and utilities to quickly incorporate new information and respond to novel opportunities could better position them to gracefully and cost-effectively navigate future challenges. For example, such reforms could include improvements to utility planning, establishing more robust and accessible stakeholder engagement processes, and adopting policies that support utility and third-party innovation.^{xxv}

xxv Potential reforms to utility planning processes are discussed later in this report in relation to Strategy 1. For more on stakeholder engagement and innovation policies, see Rebane and Goldenberg, *How to Restructure Utility Incentives*, RMI, 2024, p. 44.

The Framework

In this section, we present the strategic framework for cost control in more detail. The framework includes seven strategies, each of which represents a different angle from which PUCs — as well as consumer advocates and other stakeholders — can approach the challenge. We will briefly discuss the logic of each strategy and then offer specific levers that can be used by PUCs to operationalize it. These framework components are summarized in Exhibit 14.

We aim to provide the most salient information about each lever in a brief and digestible format, rather than attempting to cover all potentially relevant considerations and implementation details. For readers who would like more information about a lever, we offer a short list of suggested resources for further reading.

Exhibit 14

A strategic framework for utility cost control



We believe this framework can support regulators in various ways. For example, it could help regulators understand which cost-control strategies may be most appropriate to consider across utility planning, investments, and operations, given the most significant cost drivers in a state. It could help them evaluate which reforms may be necessary to address perverse incentives that are exacerbating affordability

challenges. It could also be used to clarify the potential interactions between levers, including how they could complement one another to encourage cost-effective decision-making across different spheres of utility activity. In states where some levers have already been adopted, the framework could be used to explore which levers are working as intended and which may require design changes in order to achieve desired outcomes. Though not every lever will be appropriate for all states, consideration of whether there are mechanisms in place to support each of the seven strategies for cost control may also be of value.

Although the framework itself provides a rich range of policy options, it is not an exhaustive list of all ways PUCs could encourage utilities to carefully manage their costs. Regulators may wish to consider additional policies that could play complementary roles to the 16 levers included in the framework. For instance:

- **Greater data transparency can improve visibility into utility cost trends and how spending decisions are made.** Enhanced transparency can provide greater clarity on the needs prompting utility investments, reveal the true costs and benefits of various solutions, and support consideration of alternatives to utility-proposed projects — all of which could support the efficacy of a number of levers described in this report. Management audits can create a complementary opportunity to identify structural and operational improvements to the utility's business that can result in cost-efficiencies for ratepayers.^{xxvi} Greater visibility into utility activities could also enable benchmarking against comparable utilities, which could serve as a helpful input to traditional prudence reviews.
- **Certain categories of costs could be classified as ineligible for recovery.** For example, some states have determined that expenses connected to political lobbying, executive use of private jets, trade association dues, rate case preparation and filing, and certain components of executive compensation (e.g., those tied to stock performance) are not recoverable from ratepayers.^{xxvii} Unlike denying cost recovery during the prudence review process, this approach has the benefit of categorically preventing the utility from seeking recovery for certain categories of costs that its regulators believe are best borne by shareholders.
- **Leveraging non-ratepayer funding sources could help reduce customer bills.** For some cost categories, such as wildfire mitigation, climate resilience, or low-income programs, it may be possible to leverage other sources of funding (i.e., state and federal grants, loans, bonds, or tax revenues). This approach would not promote utility cost control but instead could reduce the share of costs ultimately borne by the utility's ratepayers. It could thus serve as a complement to the levers included in the framework.

^{xxvi} For example, a management audit in Hawaii revealed \$25 million of annual capital and operational cost reductions. See Docket No. 2018-0088, "Decision and Order No. 37507," Hawaii Public Utilities Commission, December 23, 2020, https://puc.hawaii.gov/wp-content/uploads/2020/12/2018-0088.PBR_Phase-2-DO.Final_mk_12-22-2020.E-FILED.pdf. In Illinois, statute required the Commission to conduct an audit on utilities' capital projects placed into service since 2012, efforts to optimize reliability and resilience, deficiencies that could impact the planning process, and to set a baseline for the use of MRPs. See The Climate and Equitable Jobs Act, Public Act 102-0662, State of Illinois, September 15, 2021, <https://epa.illinois.gov/content/dam/soi/en/web/epa/topics/ceja/documents/102-0662.pdf>. Recently, New York initiated a proceeding to conduct audits of all gas, electric, and water utilities' management incentive compensation programs. See CASE 25-M-0043, "Order Initiating an Operations Audit," New York Public Service Commission, February 13, 2025, <https://lnkd.in/eeeW9vYi>.

^{xxvii} Several states have taken steps to prevent utilities from passing certain expenses on to customers. For example, Connecticut's utility regulator, acting under authority granted by Senate Bill 7 (passed in 2023), reduced the revenues of Connecticut Natural Gas and Southern Connecticut Gas by declining proposed costs such as advertising, marketing and promotion, and lobbying. Similarly, Colorado prohibits utilities from charging ratepayers for political lobbying expenses and promotional advertising. Maine has also enacted legislation prohibiting utilities from charging customers for lobbying costs. See Karlee Weinmann and Itai Vardi, *Power Trip: How Utilities Use Customer Money To Fund Lobbying, Corporate Branding, and Luxury Lifestyle Expenses*, Energy and Policy Institute, 2024, <https://energyandpolicy.org/report-utility-lobbying-advertising-spending/>; Joe O'Leary, "Utility Regulators Slash Gas Company Revenues Thanks to Priority Bill by Senate Democrats," November 27, 2024, <https://www.senatedems.ct.gov/utility-regulators-slash-gas-company-revenues-thanks-to-priority-bill-by-senate-democrats>; and Charlie Spatz, "Maine Becomes Third State This Year To Pass Legislation Prohibiting Utilities from Charging Ratepayers for Political Activities," June 21, 2023, <https://energyandpolicy.org/maine-utility-accountability-legislation/>.

The first strategy is to anticipate likely needs when planning for the future. Robust planning is key to ensure that necessary investments are made, to secure those investments at the lowest cost, and to avoid wasting resources on assets and activities that are not needed. To achieve these objectives, planning should be routine, transparent, and based on realistic expectations. Two levers that regulators can employ to support this strategy are improved planning processes and the careful consideration of stranding risk.

Improved Planning Processes

Lever definition: Improved planning entails the adoption of high-quality, integrated planning processes for utility generation resources, transmission, and distribution. This includes the adoption of planning processes where none currently exist, as well as the refinement of existing processes.

How this lever supports cost containment: The electric system has been called the most complex machine ever built, and updating complex systems cost-efficiently requires careful planning. This is particularly true as utilities are being asked to optimize against a greater number of objectives, including resilience, cybersecurity, and wider policy goals. Today, more solutions to the problems facing the grid are available than ever before; these include innovations on both sides of the meter and ones owned by entities other than the utility. Well-designed planning processes can help ensure all potential solutions are considered and that the best, most cost-effective options are selected for the problems regulators and utilities are attempting to solve.

Implementation tips: The topic of planning is complex and multifaceted, but key reforms that regulators can consider include:

- **Adopt transparent and inclusive planning processes for all key aspects of the utility business.** Many states with vertically integrated utilities have resource-planning requirements, but PUCs can consider requiring utilities to submit T&D plans as well. PUCs can also take steps to enhance the transparency and inclusivity of utility planning, such as by identifying the state policies that utilities should consider when developing their plans, specifying how stakeholders should be engaged,^{xxviii} providing stakeholders access to key data, enabling stakeholders to request that models be run with alternative inputs or assumptions to test sensitivities and to robustly explore alternative solutions, and providing detailed guidance on what utilities should report in their final plans.
- **Develop guidelines for considering nontraditional solutions.** Nontraditional solutions, such as demand flexibility, GETs, advanced conductors, and non-wires alternatives, should be fully considered in utility planning processes.^{xxix} PUCs can require that utilities systematically consider

^{xxviii} The International Association for Public Participation has created a framework defining five modes of engagement. This can be a helpful tool for regulators, utilities, and stakeholders to align on how stakeholders should be engaged in utility- and commission-led processes. Clear communication in advance with stakeholders to inform them which mode they will be asked to engage in can be a powerful mechanism to support productive engagement. See *IAP2 Spectrum of Public Participation*, IAP2, 2018, https://iap2.org.au/wp-content/uploads/2020/01/2018_IAP2_Spectrum.pdf.

^{xxix} For an analysis of the cost-efficiencies available through the expanded use of GETs, see Siegner et al., *GETting Interconnected in PJM*, RMI, 2024.

these solutions, that they utilize transparent screening processes administered by neutral parties, and that they assess the cost-effectiveness of each alternative.^{xxx}

- **Coordinate planning processes within the utility and among organizations.** Not all planning processes are overseen by PUCs; for example, in some states, PUCs oversee distribution planning while regional transmission organizations or independent system operators develop transmission plans. In addition, sometimes silos exist within utilities that prevent effective communication among planning divisions. To ensure planning takes the big picture into account, PUCs can provide guidelines for how generation, distribution, and transmission planning should be coordinated across entities, work with other organizations to improve information flow, and encourage utilities to develop closer coordination among their internal planning teams.
- **Establish mechanisms to support the evaluation of resilience investments.** It is important that utilities invest to increase grid resilience, but it can be challenging to ensure that a particular investment is the best way to achieve a particular resilience goal. PUCs can support both resilience and cost control by creating precise resilience metrics, well-defined protocols for calculating net benefits, and clear methods for evaluating the contribution of investments toward desired outcomes. These tools can then be employed by the utility to conduct a system-wide appraisal of the system's vulnerability to severe weather and other threats. Such actions could support the identification of no-regrets resilience investments.

Further reading

- For more information on distribution system planning processes, including useful frameworks, state examples, and requirements across the country, see “[Integrated Distribution System Planning](#),” Lawrence Berkeley National Laboratory, accessed November 22, 2024.
- For a discussion of potential reforms to resource planning processes, see Mark Dyson, Lauren Shwisberg, and Katerina Stephan, [Reimagining Resource Planning](#), RMI, 2023.
- For guidance on how PUCs can implement comprehensive planning reforms, as well as how they can coordinate their processes with those of independent system operators and regional transmission organizations, see [Blueprint for State Action: NARUC-NASEO Task Force on Comprehensive Electricity Planning](#), National Association of Regulatory Utility Commissioners (NARUC), 2021.
- For recommendations, questions, and considerations related to enhancing resilience through distributed energy resources (DERs) and incorporating resilience into utility planning, see Kiera Zitelman, [Advancing Electric System Resilience with Distributed Energy Resources: Key Questions and Resources](#), NARUC, 2020.

xxx Maine and Connecticut have established non-wires programs that require utilities to pass distribution plans to third-party administrators. In Maine, the non-wires alternatives coordinator is a consultant to the state-appointed consumer advocate's office. In Connecticut, the Public Utilities Regulatory Authority (PURA) process monitor is a consultant for the commission. The Maine administrator request for proposal details the scope of the non-wires alternatives coordinator role: Docket Number, “RFP# 202401010 Non-Wires Alternatives Coordinator,” State of Maine Office of the Public Advocate, August 2023, https://www.maine.gov/meopa/sites/maine.gov.meopa/files/inline-files/2024-01-26_RFP%20202401010%20NWAC_FINAL.pdf. The Connecticut non-wires solutions (NWS) process monitor is supporting a competitive process for comparing potential NWS against traditional distribution system capacity upgrades and other utility expenses. See Docket No. 24-08-08, “Proposed Decision,” Public Utilities Regulatory Authority, November 22, 2024, [https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/0e2fe8480f49c34b85258bdd005e7cac/\\$FILE/24-08-08%20PFD.pdf](https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/0e2fe8480f49c34b85258bdd005e7cac/$FILE/24-08-08%20PFD.pdf). Hawaii and New York are both examples of states that have established non-wires alternative screening methodologies. See *Appendix F: NWA Opportunity Evaluation Methodology*, Hawaiian Electric, 2023, https://hawaiipowered.com/igpreport/09_IGP-AppendixF_NWAOpportunityEvaluationMethodology.pdf; and *Distributed System Implementation Plan*, Consolidated Edison, 2023, pp. 168–178, <https://cdne-dcxprod-sitecore.azureedge.net/-/media/files/coned/documents/our-energy-future/our-energy-vision/distribution-system-platform/distributed-system-implementation-plan.pdf?>



Consideration of Stranding Risk

Lever definition: To address reliability concerns and potential load growth, utilities have been proposing — and PUCs have been approving — investments in fossil fuel infrastructure (e.g., gas-fired power plants, gas distribution infrastructure) that are expected to last for 40 or 50 years. Yet state policy goals, existing federal regulations (such as US Environmental Protection Agency rule 111d of the Clean Air Act), and the possibility of more stringent future regulations create a risk that these fossil-based investments will cease to be used and useful before they are fully depreciated. Moreover, the continued projection of cost declines for renewable and storage technologies enhances the risk that fossil fuel investments that currently appear economic will not remain so over time. In other words, there is a risk that this infrastructure may be retired early, which could mean that any undepreciated balances end up as stranded assets that utilities will nevertheless expect cost recovery for. Regulators can reduce the risk that future customers will be left holding the bag for obsolete infrastructure by considering asset-stranding risk when utilities propose new fossil fuel projects, and by valuing the asset in line with its likely benefits to ratepayers.

How this lever supports cost containment: A project that appears cost-effective on the basis of, for example, a 45-year service life may prove to be a poor investment if it is retired after 20 years to meet state climate goals. Considering stranding risk prior to approving a project can help prevent wasteful spending and avoid saddling future ratepayers with unnecessary costs.

Implementation tips: To evaluate whether an investment is reasonable to pursue despite having some risk of stranding, a commission can carefully consider the value it is likely to actually provide to future ratepayers. For example, PUCs could:

- **Require the use of realistic expected lifetimes in all analyses.** When a fossil fuel–related investment is proposed, regulators can carefully consider whether the expected service life proposed by the utility is realistic in light of current circumstances. And if it is not, they can require that a shorter time horizon be used in all analyses.
- **Evaluate the asset’s value under different possible futures.** Regulators can conduct a formal assessment of an asset’s stranding risk. Such an analysis could consider different possible

developments that could affect the asset’s value (e.g., state and federal policy actions, cost trajectories of competitive solutions), assess the chance of each one occurring, and enable the joint impact of multiple developments to be evaluated. The assessment could also compare the proposed fossil asset with alternative solutions, including ones that cost more to build but carry less stranding risk.^{xxx}

- **Align cost recovery with the expected value of the asset.** If the PUC determines it is in the public interest to invest in an asset that is expected to provide more value in the first few years than later (e.g., a natural gas pipeline that carries less gas over time) or that is at risk of stranding, it can consider adopting a depreciation profile for ratemaking purposes that better matches cost recovery to the timing of benefits. For example, regulators could allow cost recovery for the first few years of a longer depreciation timeline (e.g., the first 15 years of a 30-year timeline), and then require the utility to revalue the asset based on its current market value — at which point subsequent recovery would be based on that updated value. Another way regulators could adjust cost recovery to reflect an asset’s expected value to ratepayers over time would be to authorize a differentiated ROE for new fossil fuel projects that is lower than the utility’s standard ROE. This would reflect the lower value to ratepayers of utility capital that is invested in risky assets while also reducing the likelihood that the utility will propose uneconomic new fossil projects.^{xxx}

Further reading

- For more information about the risks associated with investing in new gas power plants and how clean energy portfolios can serve as cost-effective alternatives — thereby reducing the risk of stranded assets — see Lauren Shwisberg et al., *Headwinds for US Gas Power*, RMI, 2021.
- For an analysis suggesting that a 90% clean grid is feasible by 2035 without new investment in gas capacity, see pp. 25–26 of Emilia Chojkiewicz et al., *The 2035 Report*, Goldman School of Public Policy at the University of California Berkeley and GridLab, 2024.
- For more information on financing tools that can be used to address the stranded costs associated with existing assets, see Uday Varadarajan, David Posner, and Jeremy Fisher, *Harnessing Financial Tools to Transform the Electric Sector*, Sierra Club, 2018.

^{xxx} For example, a \$40 million investment with a proposed useful life of 40 years will generate a depreciation expense of roughly \$1 million per year. However, analysis suggests that the asset should be retired in 10 years, in which case the depreciation expense impact is \$4 million per year. If the asset is indeed built and retired after 10 years, ratepayers will pay 300% higher depreciation rates for the same investment. The investment may or may not still be prudent, depending on the circumstances. However, if compared to an alternative clean energy investment of \$65 million with a useful life of 20 years — meaning its annual depreciation expense would be \$3.25 million — the seemingly “cheaper” fossil fuel project is more expensive if retired early than the more expensive clean energy solution.

^{xxx} For example, in two recent gas rate cases, witnesses recommended that certain types of gas assets receive a lower ROE than other capital assets as a way to align gas utility incentives with state climate/energy goals. In one instance, the proposal was to apply an ROE of 7.71% for new business or capital expansion projects (compared with a 9.00% ROE for all other capital projects), and in the other, the witness recommended that new business and capacity expansion projects receive an ROE of 75 basis points lower than the final approved ROE. See Dockets No. UE-240004 and UG-20005 (consolidated), “Response Testimony (Nonconfidential) of Bradley Cebulko, on behalf of Joint Environmental Advocates,” Washington Utilities And Transportation Commission, September 18, 2024, <https://apiproxy.utc.wa.gov/cases/GetDocument?docID=1979&year=2024&docketNumber=240004>; and Docket No. UG-240008, “Exhibit SDV-15: Answer Testimony of Erin T. O’Neill, Hearing Exh. 401, In re Advice No. 1029-Gas of Public Service Co. of Colo. Revise its PUC NO. 6-Gas Tariff, Docket No. 24AL-0049G (July 11, 2024),” Washington Utilities And Transportation Commission, September 25, 2024, <https://apiproxy.utc.wa.gov/cases/GetDocument?docID=777&year=2024&docketNumber=240008>.

The second strategy to encourage cost containment is to coordinate electric and gas regulation. Traditionally, PUCs conduct electric and gas oversight as separate workstreams. Yet with the advance of beneficial electrification, electric and gas solutions can increasingly act as substitutes for each other.²⁷ Continuing to regulate electric and gas utilities as if they operate in entirely separate spheres is likely to result in unnecessary duplication of energy systems, missed opportunities for cost-effective electrification, and higher customer bills.^{xxxiii}

One lever that can help regulators better coordinate electric and gas regulation is to better align the planning processes for electric and gas utilities; a second is to plan for a managed gas transition.

Better Alignment Between Electric and Gas Planning

Lever definition: Aligning electric and gas planning entails coordinating utility planning processes to ensure they are based on common assumptions and reference each other in appropriate ways, so that their results complement rather than conflict with each other.

How this lever supports cost containment: Utility planning is effectively an optimization problem, which consists of identifying the mix of investments and resources that can best fulfill multiple objectives (such as serving increased demand, replacing aging infrastructure, and meeting state policy goals). However, because electric and gas utility services are increasingly substitutes for each other, treating them as separate optimization problems will not yield the most cost-efficient solution overall. For example, offering rebates to gas customers to install efficient furnaces may appear to be a good way to reduce customer bills if the gas system is considered in isolation. However, if the gas and electric systems are considered jointly, the best solution may be to instead offer rebates to electric customers to install efficient electric heat pumps when it is time to replace their existing gas furnaces.

Implementation tips: To bring electric and gas planning into better alignment, regulators could consider a number of actions. These include the following:

- **Strengthen gas planning processes.** Although planning requirements vary by state, in many jurisdictions the requirements for gas utilities are substantially less rigorous than those for electric utilities. For example, electric utilities may be subject to formalized planning requirements overseen by the PUC in dedicated proceedings (e.g., integrated resource plans, integrated distribution system plans), whereas gas utilities may only be queried about their expected investments when they come in for a rate case or propose to replace a pipeline. If gas planning requirements are insufficiently rigorous, PUCs should consider strengthening them as part of the electric-gas alignment process. Some states have also begun to establish gas planning requirements that take into consideration both gas infrastructure replacement and non-pipeline alternatives.
- **Coordinate electric and gas planning assumptions and results.** Under the status quo approach, the separation of electric and gas utility planning may result in assumptions that conflict with each other

^{xxxiii} The focus of this report is on ways to encourage cost control in the electricity sector, so we do not examine the factors driving cost increases in the gas utility sector (e.g., pipe replacement, safety) or solutions specific to them. However, the same customer often pays both electric and gas utility bills, and whether energy is affordable is a function of both. Recognizing this, Strategy 2 supports affordability by reducing the total energy costs borne by utility customers.

(e.g., an electric utility may project electric load growth due to brisk heat-pump adoption, while the gas utility that serves the same customer base may project gas load growth due to minimal home electrification), and the planning processes may ignore the results of the other’s analyses. To remedy this, PUCs can require that electric and gas utilities adopt common assumptions and utilize the results of each other’s last analyses as inputs to their own planning processes.^{xxxiv}

- **Integrate state climate goals into planning exercises.** Electric and gas planning processes should not only be aligned with each other but also aligned with existing state policy goals.^{xxxv} For example, if a state has a net-zero-by-2040 statutory requirement, gas utilities should not be permitted to submit plans that violate that requirement by assuming gas usage will remain at the same level indefinitely.^{xxxvi}
- **Consider allowing combined gas and electric utilities to merge their rate bases.** In some cases, customers receive both gas and electric service from the same utility. To encourage that utility to view these services as potential substitutes for each other, the regulator could consider allowing it to combine all of its assets into a single rate base.^{xxxvii} This would enable the utility to file a single rate case for both sides of its business, and it could also result in more coordinated internal planning between rate cases. In prudence reviews for combined rate cases, particular attention to whether an increase to the rate base in one sector results in a decrease to the other can ensure that the combined rate base supports cost control.

Further reading

- For additional discussion of coordinated electric and gas planning, as well as an overview of the coordinated process used by the Canadian province of British Columbia, see Brad Cebulko and Thomas Van Hentenryck, *A Regulator’s Blueprint for 21st Century Gas Utility Planning*, Advanced Energy United, 2023.
- For an exploration of the current state of electric and gas system planning, and the benefits and challenges of integrating these planning processes, see Mark LeBel et al., *Opportunities for Integrating Electric and Gas Planning*, Lawrence Berkeley National Laboratory, 2025.
- The Washington Utilities and Transportation Commission is required by statute to adopt rules to implement consolidated planning requirements for large combination electric and natural gas utilities and to adopt a cost test for emissions reduction measures achieved by large combination utilities to comply with state clean energy and climate policies. To access the docket where these rules are being developed, see Docket No. U - 240281, *Rulemaking Required to Implement ESHB 1589*, Washington Utilities and Transportation Commission, April 29, 2024.

^{xxxiv} For instance, in a 2023 Order in Docket 20-80, the Massachusetts Department of Public Utilities (DPU) required gas and electric utilities to coordinate planning activities. For details, see Docket No. 20-80-B, “Order On Regulatory Principles And Framework,” December 6, 2023, Massachusetts DPU, p. 122, <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18297602>.

^{xxxv} In the same 2023 order mentioned in the prior footnote, the Massachusetts DPU also required gas utilities to file transition plans describing progress made toward meeting the commonwealth’s climate goals.

^{xxxvi} In 2024, the Colorado PUC approved Xcel Energy’s Clean Heat Plan, under which the utility is required to achieve 4% emissions reduction by 2025 and 22% reduction by 2030. The approved plan “sets the Company on a reasonable track to meet the 2030 emission target.” See Docket No. 23A-0392EG, “C24-0397 Commission Decision Granting Application With Modifications, Requiring Filings, And Issuing Certain Directives To Guide Next Clean Heat Plan Filing,” Colorado Public Utilities Commission, June 10, 2024, p. 55, https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1022521.

^{xxxvii} In 2024, the Washington legislature passed a bill to enable combined utilities to merge their electric and gas rate bases. For more information, see Supporting Washington’s Clean Energy Economy and Transitioning to a Clean, Affordable, and Reliable Energy Future, HB 1589 - 2023-24, Washington State Legislature, January 25, 2023, <https://app.leg.wa.gov/billsummary?BillNumber=1589&Year=2023&Initiative=false>.



Managed Gas Transition

Lever definition: As customer adoption of heat pumps, induction stovetops, and other substitutes for traditional gas appliances rises due to federal, state, and utility incentives and market transformation, gas usage will decline and some customers will leave the gas system. If this occurs in an uncoordinated fashion (i.e., with some but not all customers on a given segment of gas distribution pipe electrifying), the cost of the gas distribution system will not decrease much in the near term, but the utility will need to recover those costs by selling fewer therms to a smaller number of customers. This will put further pressure on rates — which could in turn motivate more customers to fully electrify and leave the gas system, exacerbating the upward pressure on rates. Under this scenario, it is likely that wealthier customers would have the ability to purchase new electric appliances and leave the gas system first, leaving low- and moderate-income customers behind to pay the higher rates. Such an outcome would be inequitable and inefficient. However, this is not the only possible route; instead, states can manage the gas transition to reduce system costs and promote more equitable outcomes.

How this lever supports cost containment: A thoughtfully planned, phased gas transition can help mitigate cost increases as usage declines. For example, the cost that will be needed to maintain different segments of the existing gas system could be assessed, and those segments that are most costly (e.g., due to the need to replace aging infrastructure or because of low customer density) could be slated for retirement first. Financial and other assistance could then be provided to customers in those segments to electrify, and once all customers have done so the utility could retire that entire portion of its system.^{xxxviii} Intentionally planning the gas transition might also help identify new services that the incumbent gas utility could provide (e.g., district heating). This could enable the utility to transition to a new business model rather than retiring all its infrastructure and personnel, and the revenues earned from the new services could help offset concurrent rate base reductions.

^{xxxviii} The cost of retiring parts of the gas system could be reduced by adopting strategies that lower financing costs, such as ratepayer-backed securitization. For more information about this lever, see the discussion about ratepayer-backed securitization in *Strategy 3: Lowering Financing Costs*.

Implementation tips: A well-managed gas transition can mitigate ratepayer impacts, but it will require years (possibly even decades) to implement. As such, states can benefit from beginning the planning process now. The following are a few steps PUCs can consider taking in the near term to manage the transition in a cost-effective manner:

- **Stop expanding the gas system.** In most jurisdictions today, existing gas customers cover the costs associated with line extensions to new customers (e.g., newly built subdivisions) under the assumption that the new customers will pay off those costs by consuming gas well into the future. However, the assumption of permanent gas usage is no longer valid. Its continued use in gas line extension calculations misrepresents the true costs to add gas service, compared with constructing new buildings to be all electric, and results in inefficient system expansion.^{xxxix}
- **Consider alternatives to gas infrastructure investments.** When a utility considers making a capital investment, whether to serve a new customer or to replace existing gas infrastructure, the PUC should require it to consider whether another alternative would be more cost-effective. For instance, in some cases electrification may be cheaper than new gas infrastructure. Alternatively, a utility might find that repairing an existing pipe segment may cost less than a full replacement, and the shorter expected lifespan of the repaired asset may align better with expected gas system retirement dates. These options can be considered within a non-pipeline alternative framework.
- **Open a dedicated proceeding to consider a managed transition.** A well-managed gas transition offers substantial benefits, but planning it will require dedicated effort by the PUC and other parties. Opening a proceeding focused on this topic can help initiate the necessary discussions to support a cost-efficient gas transition.^{xl}

Further reading

- For more information on non-pipeline alternatives and a series of case studies, see Abigail Lalakea Alter et al., *Non-Pipeline Alternatives: Emerging Opportunities in Planning for US Gas System Decarbonization*, RMI and National Grid, 2024.
- For information about states that have managed gas transition proceedings, see Michael Gartman, Abigail Alter, and Sherri Billimoria, *The Case for Natural Gas Transition Planning*, RMI, 2023.
- For additional ideas on how to create a path to wind down gas distribution systems safely and affordably, see Sherri Billimoria and Mike Hennen, *Regulatory Solutions for Building Decarbonization: Tools for Commissions and Other Government Agencies*, RMI, 2020.
- For a discussion of various strategies PUCs can adopt to support a managed gas transition and real-world examples, see Brad Cebulko et al., *Regulatory Approaches for a Cost-Effective Gas Transition: Ratemaking, Incentives, and Other Tools*, Advanced Energy United, 2024.

^{xxxix} Rather than declining in recent years, gas utility spending on the distribution system has in fact grown dramatically, and subsidizing new line extensions has contributed to this trend. For more details, see Abigail Lalakea Alter, Sherri Billimoria, and Mike Hennen, *Overextended: It's Time to Rethink Subsidized Gas Line Extensions*, RMI, 2021, <https://rmi.org/insight/its-time-to-rethink-subsidized-gas-line-extensions/>.

^{xl} For example, the Massachusetts Department of Public Utilities' proceeding 20-80 established a framework of regulatory principles to move "beyond gas" and initiated several efforts to investigate policies such as line extensions and non-pipeline alternatives. See Docket No. D.P.U. 20-80-B, "Order on Regulatory Principles and Framework," Massachusetts Department of Public Utilities, December 6, 2023, <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18297602>.

Strategy 3

Lower Financing Costs

The third strategy to support cost containment is to reduce utility financing costs. Because the utility business is very capital-intensive, capital investments make up the lion's share of utility revenue requirements. The capital costs that utility customers ultimately pay for through their bills include two components: (1) the return *of* capital (i.e., the depreciation expense), and (2) the return *on* capital (i.e., the financing costs).

The return the utility is allowed to earn is determined by multiplying an allowed rate of return (which is chosen by the regulator) by the utility's rate base (which consists primarily of the undepreciated balance of its capital investments). The rate of return itself is a weighted average of the allowed return on debt and the allowed ROE. Since a utility's financing costs can be substantial, reducing these costs can significantly lower customer bills.

Two levers available to regulators who are interested in lowering financing costs are ROE reform and ratepayer-backed securitization.^{xli}

ROE Reform

Lever definition: This lever consists of reducing the utility's allowed ROE to more closely align with its true cost of capital. Reducing the share of equity in the utility's capital structure (i.e., reducing the amount of equity and increasing the amount of debt) can also be considered since the cost of equity is higher than the cost of debt.

How this lever supports cost containment: Regulators generally have good visibility into the amount a utility needs to pay its debt obligations (because this is just the weighted average of the interest rates on all the utility's outstanding bonds), so they can typically set this part of the return very close to the utility's true cost of debt. However, determining the utility's true cost of equity is more difficult — and evidence suggests that regulators routinely set the allowed ROE substantially above the level needed to attract equity investors.^{xlii} Reforming the way the allowed ROE is set and adjusting the share of equity in the utility's capital structure subject to that return are two approaches that can reduce the cost paid by utility customers while still providing investors an opportunity to earn a reasonable return.^{xliii}

xli Although the focus of this strategy is lowering the financing costs of utility-owned assets, the use of third-party capital may sometimes be able to reduce project financing costs. For example, with tax credits and loan programs made available by the federal government, other private entities can more readily make use of tax equity and debt at a higher leverage to secure lower financing costs and reduce total project costs. Partnerships with publicly owned or co-op utilities may also allow investor-owned utilities to leverage those entities' lower costs of capital.

xlii Evidence indicates that US regulators typically set the allowed ROE substantially above the true cost of equity. For example, see David C. Rode and Paul S. Fischbeck, "Regulated Equity Returns: A Puzzle," *Energy Policy* 133 (October 2019): 110891, <https://doi.org/10.1016/j.enpol.2019.110891>; and Albert Lin, "Electricity Bills Too High? Then, Get the ROE in Line," Pearl Street Station Finance Lab, accessed June 21, 2024, <https://www.pssfinancelab.com/post/electricity-bills-too-high-then-get-the-roe-in-line>.

xliii Debt is a less costly financing mechanism for ratepayers than equity. If the utility's approved capital structure features a higher ratio of equity to debt, the cost of equity will have greater influence on the weighted average cost of capital in rates, costing ratepayers more. There are also incremental tax costs that apply to ROE that are not applicable to debt financing. See Docket No. 17-10-46RE04, "The Office of Consumer Counsel's Brief," State of Connecticut Public Utilities Regulatory Authority, July 24, 2024, [https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/96ce2cd473680f9e85258b640069e373/\\$FILE/17-10-46RE04%20OCC%20Brief%20_%2007.24.2024.pdf](https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/96ce2cd473680f9e85258b640069e373/$FILE/17-10-46RE04%20OCC%20Brief%20_%2007.24.2024.pdf). Although the framework for cost containment presented in this report is intended primarily for state regulators and stakeholders, reducing the allowed ROE included in the formula rates FERC employs for interstate transmission costs could also contribute to cost containment. For more information about this idea, see Wayner, Rebane, and Teplin, *Mind the Regulatory Gap*, RMI, 2024.

Implementation tips: PUCs typically rely on analyses by expert witnesses retained by utilities to help them set allowed ROEs. These analyses often involve both quantitative models and an assessment of the allowed ROEs among similar utilities, both of which can contribute to the adoption of allowed ROEs that are higher than necessary. To address this issue, PUCs could adopt the following approaches:

- **Require that quantitative models reflect best practices supported by academic research.** Sometimes the assumptions underlying quantitative models used by industry analysts and utility consultants are questionable and the inputs used are unrealistic, resulting in unreasonably high recommendations for the allowed ROE. Requiring that the modeling approach be updated to reflect best practices supported by academic research can help.^{xliv} Regulators can also conduct a simple check on model outputs by comparing results with the expected return of a diversified basket of stocks — because a relatively low-risk utility should not provide a greater return than a diversified stock portfolio.
- **Reject the use of allowed ROEs for similar utilities.** Given the evidence that regulators routinely set allowed ROEs higher than necessary, the allowed ROEs that are in place for other similar utilities are likely not a good benchmark for the value a regulator should adopt.^{xlv}

Further reading

- For an overview of the traditional tools for determining allowed ROEs, see John D. Quackenbush, *Cost of Capital and Capital Markets: A Primer for Utility Regulators*, prepared by NARUC for the US Agency for International Development, 2019.
- For a digestible presentation about the need for ROE reform, see Mark Ellis, *Demystifying Utility Rate of Return*, prepared by Sempra Energy for the National Association of State Utility Consumer Advocates, 2023.
- For an exploration of the growing gap between allowed ROEs and cost of equity estimates in the United States, see Karl Dunkle Werner and Steven Jarvis, *Rate of Return Regulation Revisited*, Energy Institute at Haas, 2024.
- For an analysis of the impact of inflated ROEs on customer bills, an exploration of why ROEs are higher than necessary, and an evaluation of the validity of arguments against lowering ROEs, see Joe Daniel, Ryan Foelske, and Steve Kihm, CFA, *Rebalancing Return on Equity to Accelerate an Affordable Clean Energy Future*, 2025.

xliv For example, analyst-estimated growth rates, when used as inputs to models that apply the rate in perpetuity, overstate the cost of equity. Long-term growth rates, which should fall between the expected rate of inflation and gross domestic product growth, should be used instead. As another example, forecasted interest rates (which are used as a baseline in certain models) have been shown to overstate actual interest rates by over one percentage point. For details, see Steve Kihm and Mikhaila Calice, *Investment Professionals' Interest Rate Forecasts Have Been Too High Every Year for the Past 21 Years*, 2022, p. 2, <https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=447016>.

xlv It is worth noting that Order E-11, which FERC issued in 2019, recommends against relying on decisions of other jurisdictions. See Docket No. E-11 ER19-2846-002, "In Reply Refer To: Trans Bay Cable LLC," FERC, November 19, 2020, <https://ferc.gov/media/e-11-er19-2846-002>.

Ratepayer-Backed Securitization

Lever definition: Ratepayer-backed securitization is a financing approach in which a utility replaces its existing mix of debt and equity financing for a particular asset with long-term bonds backed by its ratepayers. These bonds are of low risk to potential investors due to the assurance of repayment provided by the protections typically included in state securitization legislation, which support the steady stream of ratepayer revenue. As a result, interest rates on these AAA-rated bonds are much lower than utilities' usual rates of return (e.g., 3%–4% instead of 8%–10%).^{xlvi} The use of ratepayer-backed securitization can thus substantially reduce financing costs for the asset (or, in some cases, for a portfolio of assets).

How this lever supports cost containment: Ratepayer-backed securitization has been used for decades to reduce the burden on customers of unanticipated prudently incurred expenses (e.g., storm costs, fuel-price shocks), but it can also be used to enable the retirement of uneconomic coal plants and to support a managed gas system transition.^{xlvi} For example, over the past few years, renewables have become a cheaper source of electricity than coal, yet retiring a coal plant before the end of its planned lifetime generally means customers are expected to pay for the accelerated recovery of the undepreciated plant balance just as the bill impact of renewable replacements is likely to be greatest. Ratepayer-backed securitization can be used to refinance the plant's remaining balance while retiring it ahead of the original schedule. This enables customers to benefit from the operational closure of uneconomic plants immediately, while lowering the financing cost of the retired coal capacity. Securitization spreads the bill impact of a large cost over time, and it also lowers the cost of capital to a level appropriate for a nonoperating purely financial asset.^{xlvi} In these ways, it eases the burden on customers of retiring old, uneconomic assets and adopting the new generation and storage technologies that are necessary to replace them.

Implementation tips: For a PUC to employ ratepayer-backed securitization for a particular type of asset, enabling legislation is typically needed. In some states, such legislation will need to be passed before the PUC can employ this lever. PUCs considering the use of securitization can consider the following actions:

^{xlvi} As of September 2024, the trailing five-year average of the monthly Moody's Seasoned Aaa Corporate Bond Yield (equivalent to Standard & Poor's AAA rating) was 3.71%. See "Moody's Seasoned Aaa Corporate Bond Yield," Federal Reserve Economic Data, November 1, 2024, <https://fred.stlouisfed.org/series/AAA>. However, a recent change in how utility securitization bonds are classified for passive investing has increased the cost of capital for issuers and thus for ratepayers. In 2022, one major indexer, which had previously treated utility securitizations as corporate bonds, opted to reclassify the instruments as asset-backed securities, or ABS. Since major categories of investors are precluded from owning ABS, this move effectively reduced demand for the bonds, pushing prices downward and yields upward. This change has eroded the savings potential that securitization can offer, though savings are still meaningful. The US Securities and Exchange Commission (SEC) has been considering increased regulation of indexing firms to mitigate these risks. Involvement by utility regulators, governors, and legislators in this SEC effort could help restore the full potential of securitization as a tool for reducing ratepayer costs. See Andrew Ackerman, "Bonds Got Relabeled. Now Millions of Americans Get Higher Electric Bills," *The Wall Street Journal*, March 28, 2024, <https://www.wsj.com/finance/bonds-got-relabeled-now-millions-of-americans-get-higher-electric-bills-d765c609>.

^{xlvi} Securitization can help mitigate ratepayer costs in utility sectors facing significant shifts, in contrast to traditional regulatory frameworks that often pass stranded asset risks to ratepayers. By allowing large, unexpected expenses to be spread over time, securitization offers a financial buffer that aligns better with the cost dynamics of a contracting or transitioning sector. For example, as the pace of electrification continues, the cost burden of retiring gas system assets can be securitized and spread across remaining gas ratepayers, as well as electricity ratepayers for dual-fuel utilities that are allowed to implement rate structures that distribute the transition costs. Under the latter approach, ratepayers who electrify remain responsible for the cost of legacy assets from which they previously benefited (i.e., remaining gas utility customers are not unfairly burdened with all remaining system costs). For more about how this can work, see *Regulatory Approaches for a Cost-Effective Gas Transition: Ratemaking, Incentives, and Other Tools*, Prepared by Strategen for Advanced Energy United, 2024, <https://blog.advancedenergyunited.org/reports/regulatory-approaches-for-a-cost-effective-gas-transition>.

^{xlvi} Because of the length of time, the total financing costs of securitization can be higher, depending on the type of expense and how the utility would otherwise finance it. Consider an example where an extraordinary storm results in \$1 billion in storm-related costs, of which the majority are operations and maintenance expenses that would otherwise be recovered over the course of five years. The use of securitization in this case would increase the total financing costs recovered from ratepayers, who would pay a lower interest rate but over a longer term. However, even if securitization resulted in the same overall total cost as traditional recovery, it would reduce the immediate rate impact to customers.

- **Employ capital recycling to bolster the ratepayer-savings potential of a securitization bond.**
The historical rule of thumb for securitization bonds is that the repayment charges should not exceed 10% of a utility's revenues.^{xlix} However, a work-around to this constraint called capital recycling can increase the total ratepayer savings created by a securitization bond. Capital recycling is the practice of using longer-tenure low-interest loans to refinance rate-based assets that are less attractive to investors (because they are closer to retirement) and then employing the freed-up balance-sheet capital to invest in new assets with long recovery periods and little risk of disallowance or early retirement. Capital recycling could be used to support investment in newer technologies that support a more resilient future grid.²⁸
- **Implement securitization in tandem with complementary investments to mitigate future risk.^l**
Securitization that is applied to large unexpected costs can help mitigate the financial impact of fuel-price volatility, climate and storm damages, and geopolitical upheaval on ratepayers. However, the benefits of securitization will be short-lived if utilities continue to invest in technologies that will perpetuate ratepayer exposure to the same risks that necessitated the use of securitization in the first place (i.e., fossil resources). If securitization is used to facilitate investments in the technologies necessary to cost-effectively usher the grid into a cleaner, more resilient future, the full cost-control benefits of securitization could be realized.

Further reading

- For an overview of ratepayer-backed securitization and how states have been using it to facilitate the retirement of uneconomic coal plants, see Christian Fong, "[Securitization in Action: US States Continue to Retire Coal and Reduce Electricity Rates](#)," RMI, May 24, 2022.
- For more information on how ratepayer-backed securitization works, see Paul Bodnar et al., [How to Retire Early: Making Accelerated Coal Phaseout Feasible and Just](#), RMI, 2020.
- For a comparison of enabling legislation passed in three states, see Ron Lehr and Mike O'Boyle, [Comparing 2019 Securitization Legislation in Colorado, Montana, and New Mexico](#), Energy Innovation, 2020.
- For an example of analytical evidence that demonstrates how securitization with capital recycling can support a credit-rating neutral or positive outcome, see Docket No. E015/GR-16-664, "[Direct Testimony of Uday Varadarajan, On Behalf of Clean Energy Organizations](#)," Minnesota Public Utilities Commission, May 31, 2017, and Docket No. E015/GR-16-664, "[Rebuttal Testimony of Uday Varadarajan, On Behalf of Clean Energy Organizations](#)," Minnesota Public Utilities Commission, June 29, 2017.

^{xlix} Exceeding this threshold can lead to legal challenges to either the PUC financing order or to the underlying securitization legislation. Securitization bonds more than this level are also more likely to receive a lower rating from credit rating agencies (or if previously issued, risk a downgrade). Each of these outcomes may result in a higher interest rate, diminishing the benefit of securitization. For more, see Moody's, *Utility Cost Recovery Charge Securitizations Methodology*, 2022, <https://ratings.moody.com/api/rmc-documents/396216>.

^l Although different from securitization, Energy Infrastructure Reinvestment (EIR) loans administered by the DOE Loan Programs Office can offer many of the same benefits when used in tandem with capital recycling. The key difference is the use of guaranteed federal loans, rather than state-enabled ratepayer-backed bonds supported by credit enhancements (e.g., a pledge by the state not to impair the property rights backing the securitization, and a true-up mechanism to ensure that revenues are collected from customers in a way that enables timely debt servicing). The EIR loan program is set to expire at the end of September 2026, so unless Congress extends it, utilities will need to submit their EIR applications no later than December 2025 to provide sufficient time to enter into conditional commitments with the DOE prior to the expiration date. Regulators interested in leveraging this low-interest financing should act quickly to ensure their utilities have evaluated the program's potential to create ratepayer savings and are considering a financing structure that will maximize the savings opportunity. For more information about the benefits of this program, as well as how to evaluate and structure an EIR loan, see Jesse Cohen, David Posner, and Gennelle Wilson, *Modeling the DOE's Energy Infrastructure Reinvestment Program in Resource Planning*, RMI, 2024, <https://rmi.org/modeling-the-does-energy-infrastructure-reinvestment-program-in-resource-planning/>; and Christian Fong, David Posner, and Uday Varadarajan, *Maximizing the Value of the Energy Infrastructure Reinvestment Program for Utility Customers*, RMI, 2024, <https://rmi.org/maximizing-the-value-of-the-energy-infrastructure-reinvestment-program-for-utility-customers/>.

Strategy 4 Incentivize Reduced Spending

The fourth strategy to encourage cost containment is to reward the utility for finding ways to reduce the amount of money it spends across a range of cost categories. This is a departure from the traditional cost-of-service regulatory model, which instead rewards capital spending and creates only a weak incentive to reduce opex. Three levers available to regulators who are interested in pursuing this strategy are multiyear rate plans (MRPs), shared savings mechanisms (SSMs), and capex-opex equalization. These levers can incentivize a utility to contain costs as it conducts planning and makes investment decisions, and they can also influence utility decision-making in ongoing operations.

Multiyear Rate Plans

Lever definition: An MRP extends the time between utility rate cases beyond the one to two years that is typical under traditional cost-of-service regulation.

How this lever supports cost containment: Under an MRP, once a PUC has set a utility's base rates in a rate case, those rates are not reset to reflect the utility's actual costs for several years. If the utility manages to achieve savings in the costs recovered by those rates, it can benefit financially from those savings for longer than it would be able to under traditional ratemaking. This can create a strong financial incentive for the utility to reduce spending.^{li} In the long run, this can translate to reduced costs for customers when excess earnings are returned to ratepayers or when the utility's efficiency gains are translated into a reduced revenue requirement during its next rate case. However, the extent to which an MRP delivers its full savings potential is highly dependent on the details of its design.

Implementation tips: MRPs involve many different components with important design choices. The choices made can affect the strength of the cost-containment incentive created by the MRP, as well as the risk of unintended consequences to both ratepayers and the utility. For example:

- **Attrition relief mechanisms.** The amount of revenues a utility is allowed to collect under an MRP is usually adjusted in a predetermined fashion via an attrition relief mechanism (ARM). An ARM can be designed in various ways, and the utility's incentives (and hence ratepayer costs) depend heavily on the choices that are made. For instance, an ARM that bases revenue adjustments on an index-based formula rather than on a utility's forecasted costs is likely to create a stronger cost-containment incentive. When an index-based formula is used, the ARM adjusts rates to reflect changes in external business conditions (e.g., inflation), which the utility cannot control. This enables rates to adjust dynamically during the MRP term in a way that reflects key utility cost drivers without tracking the utility's actual spending decisions (which would weaken the cost-containment incentive). Another benefit of an index-based ARM is that it does not rely on utility forecasts, which inherently create an incentive for the utility to inflate forecasts at the time of the rate case.
- **Cost trackers.** The MRP's cost-containment incentive generally applies only to costs recovered via the ARM — not to any recovered via cost trackers.^{lii} Limiting the use of cost trackers to

^{li} For example, the most recent MRP implemented in Hawaii began in 2021. In the first four years of the MRP, the Hawaiian Electric Company's capital spending decreased relative to the preceding four years, and the total value of the rate base decreased in real terms. The company's spending on operations and maintenance for distribution also saw a three-year reduction relative to prior years, though it did increase in the fourth year. See Docket No. 2018-0088, "Ulupono Initiative LLC's Brief on Re-Basing Target Revenue," Hawaii Public Utilities Commission, December 5, 2024, <https://hpuc.my.site.com/cdms/s/puc-case/a2G8z0000007fLQEAY/pc21581?tabset-431dc=3>.

^{lii} A cost tracker is a mechanism to expedite cost recovery for a category of costs. It works by keeping track of what a utility spends and then performing a true-up to rates via a rider to recover exactly that amount from customers.

categories of costs that are well outside the control of the utility (e.g., taxes, social benefit program costs) can prevent cost trackers from undermining the cost-containment incentive.

- **Earnings sharing mechanisms.** MRPs often include an earnings sharing mechanism (ESM) that shares a portion of “overearnings” relative to the company’s authorized ROE with customers; some ESMs also share “underearnings.” Typically, earnings are only considered excess or deficient once the company’s realized ROE deviates from its authorized ROE by a certain amount (e.g., 100 basis points above or 200 basis points below it). The zone around the authorized ROE in which no sharing occurs under the ESM is called a deadband. An ESM is a risk-mitigation tool that reduces the risk that a utility’s actual ROE will deviate significantly from what a PUC authorizes; ESMs can thus provide a helpful safeguard. However, an ESM also reduces the cost-containment incentive created by an MRP because the utility will gain less from achieving cost savings and lose less if it overspends. The magnitude of this impact depends on the specific design of the ESM. For example, a wider deadband preserves more of the cost-containment incentive created by the MRP but limits the risk-reduction benefit of the ESM; this is a trade-off that must be considered during ESM design.
- **Plan term.** A longer MRP term tends to create a stronger incentive for the utility to pursue cost-savings opportunities. The reduced frequency of rate cases under a longer MRP also tends to reduce the administrative costs of rate case proceedings on the regulator, the utility, and other parties. In practice, most regulators have adopted terms between three and five years, indicating that this may be the sweet spot for MRPs.
- **Off-ramps.** An off-ramp (sometimes called a re-opener) guards against the risk of big surprises by specifying particular circumstances under which the regulator will consider making changes during the MRP, either by adjusting specific aspects of it or by opening a new rate case. Circumstances in which an off-ramp may be considered could include a credit-rating downgrade, an earned ROE that threatens the utility’s financial health, and excessive overearnings.
- **Impacts on service quality.** Because the cost-containment incentive of an MRP can be quite powerful, the utility may respond by underinvesting in maintenance or operations in ways that affect the quality of service for customers. Adopting performance incentive mechanisms, tracking metrics, and other reporting requirements to support utility accountability can help ensure that reliability and other core aspects of service quality are not negatively impacted during the MRP term.

Further reading

- For a more thorough overview of the components of MRPs and how to design them to encourage cost-efficiency, see Kaja Rebane and Cara Goldenberg, [How to Restructure Utility Incentives: The Four Pillars of Comprehensive Performance-Based Regulation](#), RMI, 2024, pp. 24–28.
- For additional discussion of the cost-containment incentive created by MRPs, see Mark Newton Lowry et al., [State Performance-Based Regulation Using Multiyear Rate Plans for US Electric Utilities](#), Lawrence Berkeley National Laboratory, 2017.
- For an estimate of the consumer benefits from MRPs in Australia, see [Consumer Benefits Resulting from the AER’s Incentive Schemes: A Report for Energy Networks Australia](#), HoustonKemp Economists, 2022.
- For a comparison of MRPs and formula rate plans and an explanation of how revenues can be adjusted during an MRP, see Melissa Whited and Cheryl Roberto, [Multiyear Rate Plans: Core Elements and Case Studies](#), Synapse Energy Economics, 2019.

Shared Savings Mechanisms

Lever definition: An SSM is a type of performance incentive mechanism that rewards the utility with a share of the total cost savings that result from a particular action. Some SSMs base the reward payment on an estimate of the total net benefits (which could include the value of benefits such as local economic development and carbon emissions reductions) rather than on cost savings alone.

How this lever supports cost containment: An SSM rewards the utility for finding more cost-effective alternatives to traditional solutions. This encourages the utility to actively seek ways to reduce costs. For example, an SSM could allow a utility to keep a portion of the cost difference between a traditional poles-and-wires capital investment it might otherwise pursue and a non-wires solution that will cost ratepayers less.^{liii}

Implementation tips: An SSM can be implemented in either a narrow fashion (i.e., for a specific project type) or on a broader basis as a comprehensive SSM. A comprehensive SSM can be used to create a cost-containment incentive for spending that the utility may otherwise have little incentive to reduce, such as expenditures that are recovered via cost trackers rather than through the ARM in an MRP.

Further reading

- For a discussion of SSMs in theory and practice, see Melissa Whited, Tim Woolf, and Alice Napoleon, *Utility Performance Incentive Mechanisms: A Handbook for Regulators*, Synapse, 2015, pp. 46–64.
- For a discussion of Hawaii’s comprehensive SSM, see Kaja Rebane and Cara Goldenberg, *How to Restructure Utility Incentives: The Four Pillars of Comprehensive Performance-Based Regulation*, RMI, 2024, p. 49.

Capex-Opex Equalization

Lever definition: Capex-opex equalization refers to a number of different approaches designed to equalize the utility’s financial incentive to deploy capex and opex, with the objective of mitigating or eliminating capex bias.

How this lever supports cost containment: Capex bias encourages the utility to prefer investing its own capital over opex-based alternatives, even when these may cost less or provide more benefits to customers. By putting capex and opex on a more level playing field, capex-opex equalization strategies can support the adoption of cost-beneficial alternatives such as utility energy-efficiency programs, third-party computing services, and customer-owned distributed generation.

Implementation tips: A number of capex-opex equalization approaches exist, and they vary in how broadly they address capex bias. For example, opex capitalization involves amortizing a category of opex and allowing the utility to earn a return on it. This approach is generally applied to a narrow category of opex, such as expenditures related to a particular energy-efficiency program. By contrast, a calibrated efficiency carryover mechanism — a mechanism that enables the utility to benefit equally from cost savings it achieves in any year of an MRP, and which is carefully calibrated to equalize capex and opex

^{liii} New York and Connecticut have adopted SSMs that encourage utilities to pursue non-wires solutions. To learn more about these real-world examples, see PIMs Database, RMI, <https://rmi.org/pims-database/>.



incentives — can address capex bias across a broad swath of utility expenditures. Totex (a term meaning total expenditures) ratemaking, which eliminates the distinction between capex and opex for ratemaking purposes, is another broad approach. It is important to note that while leveling the playing field between capex and opex removes a key barrier to cost-efficient decision-making, capex-opex equalization alone is not enough to incentivize cost-efficiency. To avoid just rewarding the utility for selecting the priciest solution regardless of whether it is capex or opex, it is important to adopt capex-opex equalization mechanisms in combination with other levers that reward reduced spending (such as a well-designed MRP or an SSM).

Further reading

- For some examples of capex-opex equalization approaches adopted by other jurisdictions, see Toby Brown and William Zarakas, [Improving the PBR Framework in Hawaii: Addressing the Risk of “Capex Bias,”](#) prepared by the Brattle Group for the Hawaiian Electric Companies, 2019.
- For an in-depth discussion of a totex ratemaking and a high-level overview of several other capex-opex equalization approaches, see Kaja Rebane et al., [Making the Clean Energy Transition Affordable: How Totex Ratemaking Could Address Utility Capex Bias in the United States](#), RMI, 2022.

Strategy 5 Leverage Competition

The fifth strategy to support cost containment is to better leverage competition in the regulatory context. The basic reason a utility is rate regulated in the first place is the absence of effective competition, due to the sector in which it operates being a natural monopoly.^{liv} However, even if the overall industry has the features of a natural monopoly, some parts of that industry may not. In these cases, regulators may be able to leverage the power of competition to reduce customer costs. Two levers that can be used by regulators to leverage competition are all-source procurement and the increased utilization of DERs to provide grid services.^{lv}

All-Source Procurement

Lever definition: When a vertically integrated utility (i.e., one that owns generation assets as well as T&D infrastructure) identifies a need for new generation, one option is to procure it from a third party. However, traditional utility procurement practices are unnecessarily prescriptive about the type of resource sought (for example, the utility may solicit bids for a certain number of megawatts of gas generation). All-source procurement focuses on the grid need that must be met, rather than on a particular type of resource preselected by the utility. For example, under all-source procurement, a utility might seek bids for resources that can supply a certain number of megawatt hours and a certain amount of summer peak capacity. Such a solicitation may reveal that a clean energy portfolio (i.e., a diverse set of utility-scale and demand-side resources, such as new renewable capacity, batteries, and demand response) could meet the identified need more cost-effectively than a traditional gas-fired plant. The process of evaluating bid options as a portfolio is very similar in concept to portfolio analysis in an integrated resource plan (IRP), which has led utilities and regulators to develop planning processes that effectively integrate IRPs and all-source procurement.

How this lever supports cost containment: All-source procurement leverages the power of competition to reduce costs better than traditional procurement practices. It provides more flexibility to applicants to come up with creative solutions to meet grid needs, and it invites a broader range of third parties to submit bids. Evidence indicates that clean energy portfolios are often more cost-effective than new gas power plants,^{lvi} yet the constraints imposed by traditional procurement processes in tandem with utility capex bias may prevent them from even being considered. Allowing diverse resources to compete, rather than predetermining the type of resource, can reveal ways to meet grid needs more cost-effectively.

^{liv} A natural monopoly occurs when an industry is subject to large economies of scale, such that an established company is able to outcompete any potential new market entrants. For example, once a company has invested the funds needed to build a set of electric distribution wires, the incremental cost to then send electricity over those wires to serve customers is comparatively low. This means an established company could generally undercut any firm that attempts to install a competing set of distribution wires.

^{lv} PUCs can take advantage of other opportunities to increase competition to lower customer rates. For example, for those states that allow it, community choice aggregation allows local governments to purchase electricity for their residents and businesses from an alternative supplier while still receiving T&D service from their existing utility provider. Although community choice aggregation requires local governments to pass laws enabling it for a particular municipality, regulators are usually responsible for setting standards and requirements and ensuring compliance, ensuring consumer protections, and supporting the transition. For more about community choice aggregation, see “Community Choice Aggregation,” US Environmental Protection Agency, December 2, 2024, <https://www.epa.gov/green-power-markets/community-choice-aggregation>.

^{lvi} For more information about the cost-savings opportunities offered by clean energy portfolios over gas-fired power plants, see Lauren Shwisberg, *The Business Case for New Gas is Shrinking*, RMI, 2022, <https://rmi.org/business-case-for-new-gas-is-shrinking/>.

Implementation tips: To achieve the best results, all-source procurement processes should be designed carefully and adopted as routine practice.^{lvii} For example, PUCs can:

- **Ensure that utilities clearly identify grid needs.** All-source procurement will be most effective when grid needs — as well as the timing of when those needs are likely to materialize — are well understood.^{lviii} This can be accomplished through a well-designed IRP process, so PUCs may wish to consider whether updates to their IRP processes are warranted.
- **Provide guidance to participants.** PUCs can support effective all-source procurement by defining requirements well and providing clear and appropriate guidance to both utilities and third-party bidders. For example, regulators could specify how grid needs should be defined, develop the bidding process, ensure that bidders are engaged in a way that enables fair competition,^{lix} and establish the criteria for evaluating submitted bids (e.g., how to value benefits to the system beyond the identified grid needs, such as reduced fuel costs and avoided transmission investment).
- **Employ an independent entity to oversee the bidding process.** Regulators can require that an independent party manage the bidding process. This can support fairness, increase transparency, and provide confidence to all parties that the process was conducted in an evenhanded manner.
- **Harmonize all-source procurement and planning.** Some jurisdictions use the results of all-source requests for information to inform the resource cost assumptions used in planning modeling. Such requests for information are separate from the competitive request for proposals at the end of the planning process, which are used to determine which resources should actually be procured.^{lx}
- **Learn from others.** PUCs can look to existing all-source procurement practices in other jurisdictions, including the leading examples of Washington and Colorado.^{lxi}

lvii In addition to PUC action, state legislators can support the routine use of all-source procurement by passing bills that encourage or require utilities to employ all-source procurement.

lviii All-source procurement is also likely to be more effective for grid needs that are broadly defined (e.g., system energy and capacity) rather than pertaining to specific challenges facing parts of the grid (e.g., voltage support at a given location on the transmission system).

lix For example, if a utility intends to submit a bid as part of the competitive procurement exercise, it is common to adopt safeguards to ensure the utility does not have an unfair advantage. These can include requirements that the utility team submitting the bid is not the same as (or in communication with) the team that is administering the process, as well as taking steps to prevent utilities from leveraging information that other bidders cannot access.

lx Michigan's statutory requirements regarding IRP require all-source procurement as both an input to the planning process and as the concluding step. See Act 3 of 1939: An Act to Provide for the Regulation and Control of Public and Certain Private Utilities, State of Michigan, Chapter 460.t(12), accessed November 25, 2024, <https://www.energy.gov/sites/prod/files/2015/06/f22/460PU.pdf>.

lxi Washington's Clean Energy Transition Act, which passed in 2019, requires investor-owned utilities to buy electricity through an openly competitive process. For details, see Clean Energy Transformation Act, SB 5116, 2019, State of Washington, May 7, 2019, <https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act>. The Colorado PUC specifies all-source competitive acquisition processes for utilities to acquire new resources. See Rules Regulating Electric Utilities 4 CCR 723-3, Colorado Public Utilities Commission, accessed November 25, 2024, <https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=8835&fileName=4%20CCR%20723-3>.

Further reading

- For an overview of all-source competitive solicitations, see Fredrich Kahrl, *All-Source Competitive Solicitations: State and Electric Utility Practices*, Lawrence Berkeley National Laboratory, 2021.
- For information about how to update electricity resource procurement processes, see Lauren Shwisberg et al., *How to Build Clean Energy Portfolios: A Practical Guide to Next-Generation Procurement Practices*, RMI, 2020.

Increased Utilization of Distributed Energy Resources

Lever definition: DERs, such as electric vehicles, distributed solar, batteries, smart thermostats, and heat pumps, are capable of providing a variety of grid services. Among others, these include energy, load shifting, and a variety of ancillary services. Although the deployment of DERs continues to increase, many existing DERs owned by customers and third parties are not being fully leveraged, leaving valuable benefits on the table. Supporting the aggregation of DERs (also referred to as VPPs) — either by a single technology or by multiple types — is one way PUCs could help increase the utilization of these resources and reduce system costs.^{lxii}

How this lever supports cost containment: The grid services that DERs can provide are valuable, yet this value is currently being left on the table in jurisdictions across the country. This has resulted in missed opportunities to utilize potentially more cost-effective resources to meet grid needs. Aggregated DERs, or VPPs, can address this issue by organizing large numbers of DERs to provide grid services when and where they are needed. This can both reduce grid operating costs (e.g., by avoiding the use of costly gas peaker plants, or by reducing system congestion and thus line losses) and avoid or defer the need for more expensive utility projects (e.g., distribution system upgrades).^{lxiii} Aggregated DERs can also reduce grid costs by managing load growth from new grid-connected technologies. For instance, the increased adoption of electric vehicles could drive up peak demand if charging behavior is unmanaged; however, aggregating electric vehicles with other sources of demand flexibility can help manage this additional load, mitigating costly peaks and reducing system costs. Increasing the number of DERs on the system that are flexibly managed can therefore reduce overall system costs and provide benefits to all ratepayers. With the penetration of DERs anticipated to double by 2027, the potential for increased DER utilization to reduce grid costs is likely to continue growing.²⁹

Implementation tips: PUCs can take a number of actions to support the use of aggregated DERs to contain utility costs. For instance, regulators could:

lxii Typically, DERs are owned by customers or third parties, and a third party or a utility plays the role of aggregator. Although it is possible for a utility to own the DERs, this aspect of the electricity business is not a natural monopoly. In theory, the utility could be allowed to compete against third parties for VPP opportunities, but in reality, the utility may be able to leverage the benefits it enjoys as the regulated monopoly (e.g., owner of customer relationship and grid data, greater knowledge of grid needs, the ability to reduce its own financial risk through subtle cross-subsidization) to drive competitors out of the market.

lxiii For example, one study found that VPPs could meet resource adequacy needs as well as conventional resources, but at just 40%–60% of the cost of alternative options. The researchers also found that including the value of societal benefits further increased the advantages offered by VPPs. For details, see Ryan Hledik and Kate Peters, *Real Reliability: The Value of Virtual Power (Volume I: Summary Report)*, Brattle Group, 2023, <https://www.brattle.com/real-reliability/>. Furthermore, a modeling exercise conducted on the power system in the Mountain West in 2035 found that a resource mix including VPPs reduced net generation costs by 20% or \$140 per household annually and reduced the need for new gas by 75%. For more information, see Tyler Fitch et al., *Power Shift: How Virtual Power Plants Unlock Cleaner, More Affordable Electricity Systems*, RMI, 2024, <https://rmi.org/insight/power-shift/>.



- **Enable DER adoption by all customer classes.** Adopting policies that enable widespread DER adoption — not just DERs for the economically privileged — will be essential to realizing the full benefits of aggregated DERs. DER regulations and programs should consider what is needed to enable adoption by different customer classes (e.g., on-bill financing options, educational outreach, and offerings for low- and moderate-income customers).
- **Compensate DER owners for providing value in multiple ways.** Enabling DER owners to be compensated for a range of grid services (e.g., energy, demand flexibility, ancillary services) can broaden the range of opportunities for DERs to provide cost-saving solutions to grid problems. These opportunities should include the set of services applicable to the distribution level, not only the bulk power system and customer services. In addition, compensating DER owners in multiple ways (e.g., rewarding the DER owner for being responsive to dispatch requests and offering larger payments when grid needs are greater) creates a stronger incentive for them to make their DERs available when needed.
- **Consider the regulatory reforms needed to deploy aggregations of DERs at scale.** Fully leveraging DERs to support cost containment will likely require the use of a number of the levers identified in this framework. For example, the capex bias created by the traditional cost-of-service framework works against solutions such as VPPs that might erode the utility's earnings potential. To ensure utilities are motivated to help DER programs succeed, supportive reforms such as revenue decoupling and capex-opex equalization measures can be adopted in tandem with policies specifically focused on increasing the utilization of aggregated DERs.^{lxiv}

Further reading

- For an overview of the grid services that aggregated DERs can provide, approaches to valuing those services, ways that DER aggregators and owners can be compensated for those services, and case studies, see Stephanie Bieler et al., [Aggregated Distributed Energy Resources in 2024: The Fundamentals](#), prepared by RMI for NARUC and the National Association of State Energy Officials (NASEO), 2024.
- For a set of suggested policy principles pertaining to VPPs, see The Virtual Power Plant Partnership's Regulatory and Policy Strategy Working Group et al., [VPP Policy Principles](#), RMI, 2024.
- For a discussion of the links between VPPs and social equity, see Brittany Speetles, Eric Lockhart, and Adam Warren, [Virtual Power Plants and Energy Justice](#), National Renewable Energy Laboratory, 2023.

^{lxiv} Capex-opex equalization is a lever under Strategy 4, and revenue decoupling is discussed under Strategy 6.

The sixth strategy to encourage cost containment is to avoid unnecessarily expanding the electric system. Under traditional cost-of-service regulation, the utility generally has a financial incentive to overinvest in capital projects, so taking steps to mitigate this risk is important. Overbuilding can also result from other factors, such as focusing too narrowly on traditional solutions to meet grid needs and neglecting to fully leverage energy efficiency and demand flexibility. Three levers that can support this strategy are revenue decoupling, time-varying rates, and more careful consideration of capital cost trackers. These levers can shape utility investment and operational decisions, as well as influence the assumptions and resources considered in resource planning.

Revenue Decoupling

Lever definition: A revenue decoupling mechanism (RDM) addresses the throughput incentive, which is a perverse incentive created by the traditional approach to rate design. If left unaddressed, the throughput incentive enables the utility to increase its profits by increasing energy sales, which encourages the utility to resist energy efficiency, distributed generation, and other innovations that could reduce sales. Moreover, increasing sales are often used to justify further investments in generation capacity and other infrastructure. By breaking the link between the kWh of electricity sold and the revenues collected from customers, an RDM makes the utility agnostic to sales volumes.

How this lever supports cost containment: Generating and moving more energy drives up costs in both the short run (for example, due to increased fuel costs) and in the long run (because a larger system of plants, poles, wires, and other infrastructure is needed). Moreover, energy efficiency is generally the most cost-effective way to meet demand, and distributed generation can reduce the amount of infrastructure needed to move energy from the point of production to where it is used.^{lxv} By removing the utility's incentive to increase energy sales, an RDM can prevent unnecessary system expansion.

Implementation tips: An RDM that broadly decouples utility revenues from sales (aka full decoupling) is the most effective way to address the throughput incentive. It is important to note that in some jurisdictions, the term decoupling has been used to refer to things other than RDMs, such as lost-revenue adjustment mechanisms, straight fixed variable rates, and formula rates — but these do not offer the benefits that RDMs provide and have significant drawbacks.^{lxvi}

^{lxv} Energy efficiency has generally been found to be a very cost-effective way to meet demand. For more information, see Ian Hoffman et al., *The Cost of Saving Electricity Through Energy Efficiency Programs Funded by Utility Customers: 2009–2015*, Lawrence Berkeley National Laboratory, 2018, <https://emp.lbl.gov/publications/cost-saving-electricity-through>; Natalie Mims Frick et al., “Still the One: Efficiency Remains a Cost-Effective Electricity Resource,” Lawrence Berkeley National Laboratory, August, 2021, <https://emp.lbl.gov/publications/still-one-efficiency-remains-cost>; and *Decoupling Policies: Options to Encourage Energy Efficiency Policies for Utilities*, Options to Encourage Energy Efficiency Policies for Utilities, National Renewable Energy Laboratory, 2009, <https://www.nrel.gov/docs/fy10osti/46606.pdf>.

^{lxvi} For more information about the drawbacks of lost-revenue adjustment mechanisms, straight fixed variable rates, and formula rates, see Carina Rosenbach et al., *The Nuts and Bolts of Performance-Based Regulation: Tools to Build a More Affordable, Reliable, and Equitable Grid*, RMI, 2024, <https://rmi.org/insight/the-nuts-and-bolts-of-performance-based-regulation/>.

Further reading

- For more information about the throughput incentive, its basis in traditional rate design, the mechanics of how an RDM addresses it, and the reasons RDMs offer more benefits today than ever before, see Kaja Rebane and Cara Goldenberg, *How to Restructure Utility Incentives: The Four Pillars of Comprehensive Performance-Based Regulation*, RMI, 2024.
- For additional information on specific RDM designs across the country, see Jim Lazar et al., *Revenue Regulation and Decoupling: A Guide to Theory and Application*, Regulatory Assistance Project, 2016.
- For points regulators should consider to construct an effective decoupling regime and additional insights on designing decoupling mechanisms tailored to specific state priorities and regulatory contexts, see Janine Migden-Ostrander and Rich Sedano, *Decoupling Design: Customizing Revenue Regulation to Your State's Priorities*, Regulatory Assistance Project, 2016.
- For a detailed examination of how decoupling mechanisms have been implemented in various jurisdictions and their impact on energy efficiency and utility revenues, see Wayne Shirley and Mike Taylor, *Decoupling Utility Profits from Sales: Issues for the Photovoltaic Industry*, Lawrence Berkeley National Laboratory, 2009.

Time-Varying Rates

Lever definition: Historically, electric rate designs for small customers (e.g., residential customers) have featured volumetric charges that do not depend on when usage occurs. Time-varying rates instead charge customers different amounts based on the hour, day, and/or season in which the electricity is used. The rates charged in different time periods can be set in advance (e.g., time-of-use rates, seasonal rates) or they can vary in a more dynamic fashion (e.g., critical-peak pricing, real-time pricing).

How this lever supports cost containment: Well-designed time-varying rates encourage customers to shift their usage away from peak hours to times that benefit the system overall. They do this by sending appropriate price signals about when power and grid services are most constrained. Time-varying rates are particularly beneficial when customers have access to equipment that enables them to easily manage their loads and shift them in response to price signals, such as smart thermostats and advanced metering infrastructure. Well-designed time-varying rates can encourage customers to use these technologies in grid-beneficial ways, creating near-term operational savings as well as bill savings for the participating customer. In the long term, time-varying rates can also defer capital investments that the utility would have otherwise needed to make to serve peak load (both locally and at the system level).

Implementation tips: Many US jurisdictions have experience with time-varying rates, creating a wealth of real-world knowledge that regulators can draw upon. For example, regulators who are interested in designing effective time-varying rates to support cost control may wish to:

- **Make time-varying rates the default option.** Most US jurisdictions that have implemented time-varying rates have done so on an opt-in basis, and as a result they have very low enrollment rates. However, some states (e.g., California, Hawaii, Michigan, and Missouri) have adopted them as the default for all customers (i.e., to not participate, a customer must opt out), and they have thereby achieved greater participation and associated ratepayer benefits. When implementing time-varying rates as the default option, it is important that the requisite technology (e.g., advanced metering infrastructure) is in place and that customers are given a clear path to opt out if they wish to.
- **Adopt a sizable peak-to-off-peak ratio.** When the price differential between peak and off-peak periods is greater than 4:1, the responsiveness of customers to the change in price signal increases, and the impact on peak load reduction is greater.³⁰

- **Combine preset and dynamic elements while maintaining ease of comprehension.** When time-of-use rates are combined with more dynamic pricing approaches, such as critical-peak pricing, their efficacy in providing value to the grid may increase. However, simplicity is important in rate design to ensure that customers can easily understand the structure and respond to the price signals it creates. Enabling technologies such as programmable thermostats can facilitate customer participation by allowing them to automate the control process.
- **Require customer education, communication, and evaluation.** Effective engagement can help customers understand how the time-varying rate functions, how to take advantage of it to reduce their bills, and how to navigate the transition from flat-rate billing. Effective communication and education campaigns have used email, direct mail, mobile apps, and SMS texting to deliver tips, reminders, and real-time notifications. Shadow billing — which shows customers what their bills would have looked like under the standard rate — can help customers understand the time-varying rate, ensure the price signals it creates are effective, and protect customers from detrimental impacts.
- **Incorporate the benefits of time-varying rates into planning assumptions.** For time-varying rates to defray unnecessary capital investments, resource and system planning assumptions will need to evolve to reflect potential demand savings and modified load profiles.

Further reading

- For evidence on the effectiveness of time-varying rates and design best practices, based on randomized pilots conducted by 10 utilities, see Peter Cappers and Rich Scheer, [American Recovery and Reinvestment Act of 2009: Final Report on Customer Acceptance, Retention, and Response to Time-Based Rates from Consumer Behavior Studies](#), Lawrence Berkeley National Laboratory, 2016.
- For more information about residential time-of-use rates, see Ahmad Faruqui, Ryan Hledik, and Sanem Sergici, [A Survey of Residential Time-of-Use \(TOU\) Rates](#), Brattle Group, 2019.

Careful Consideration of Capital Cost Trackers

Lever definition: A capital cost tracker is a mechanism designed to expedite cost recovery for a particular category of capital investments (e.g., advanced metering infrastructure). It does this by keeping track of what a utility spends and then performing an ex-post true-up to rates via a rider to recover exactly that amount from customers. Capital cost trackers can substantially weaken cost-containment incentives, so carefully considering when they are truly needed — and designing them well when they are — is important.

How this lever supports cost containment: In general, cost trackers tend to weaken cost-containment incentives. One reason for this is that they reduce regulatory lag (i.e., the time between when a utility incurs a cost and the time when it recovers that cost via rates) since they adjust rates regularly to recover costs rather than just when rates are reset during a rate case. A second reason is that they tend to result in less regulatory scrutiny. This is because the prudence reviews regulators conduct in periodic cost-tracker proceedings tend to be less rigorous than those conducted in rate cases.^{lxvii} Finally, cost trackers are often

^{lxvii} These downsides of cost trackers are even more marked when cost trackers are adopted in conjunction with an MRP. As discussed previously, a well-designed MRP can create a strong cost-containment incentive. However, that incentive applies only to the costs recovered through base rates — not to any costs recovered via trackers.

designed in ways that virtually guarantee cost recovery, which reduces utilities' incentive to limit costs. Although cost trackers can weaken cost-containment incentives for both capex and opex, capital cost trackers present more acute cost-containment challenges. This is because under traditional cost-of-service regulation, utilities have an incentive to increase capital spending (a perverse incentive known as gold plating), and capital cost trackers can enable utilities to more easily act on it. Regulators can mitigate the risks posed by capital cost trackers by limiting their use to cases in which they are clearly needed and by taking steps to encourage cost-efficient spending.

Implementation tips: Cost trackers may be adopted in rate cases or other types of proceedings, so to ensure they are used judiciously, regulators may wish to adopt a set of cost-tracker principles and then apply them broadly. For example, a set of principles could include the following:

1. When a new cost tracker is proposed, carefully consider the incentives it is likely to create (particularly if it is a capital cost tracker).
2. Consider ways to encourage cost-efficiency in areas where cost trackers may weaken cost-containment incentives (e.g., through a comprehensive SSM or stricter transparency requirements).
3. Consider what level of review or criteria should be used to ensure investments recovered via cost trackers are delivering expected benefits to customers.
4. Regularly reconsider existing cost trackers (e.g., as part of an annual review) and discontinue any that are determined to not be serving the public interest.
5. Assess the cumulative impact of all cost trackers on the utility's overall business risk, and account for any risk reduction when setting the utility's allowed ROE.

In addition to creating a set of principles, it may also be helpful to establish criteria that inform when a cost tracker is appropriate and will be considered by the regulator. For example, some experts suggest that cost trackers should only be approved for cost categories for which the use of a tracker is essential to protect the utility's financial health. In such cases, there should be clarity about the information needed from a utility to justify the use of a cost tracker (e.g., the probability of financial duress if costs increase beyond those included in the test year that was used to set base rates).³¹

Further reading

- For more about cost trackers, the challenges they create for cost containment, and regulators' expanded use of them in recent years, see Ken Costello, [*Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives*](#), National Regulatory Research Institute, 2014, p. 32.
- For more about the risks and benefits of carefully applied cost trackers, as well as a set of questions regulators can ask when cost trackers are proposed, see Ken Costello, [*The Two Sides of Cost Trackers: Why Regulators Must Consider Both*](#), National Regulatory Research Institute, 2009.

Strategy 7

Encourage Better Fuel-Cost Management

The seventh strategy is to encourage electric utilities to manage their use of fuels more cost-effectively. This includes finding ways to secure lower prices for fuels, dispatching generation resources in merit order, and taking fuel costs into account when making new investment decisions.

Better fuel-cost management also means paying attention to the comparative risks of relying on different types of resources. The prices of some fossil fuels can be volatile; this is particularly true of natural gas, the price of which sometimes spikes to extreme levels when supply is constricted.^{lxviii} In contrast, resources such as wind, solar, and battery energy storage involve no fuel, and thus there is no risk of sudden fuel-price spikes. Under traditional cost-of-service regulation, it is primarily customers rather than utility shareholders who bear the risk of fuel-price volatility and pay the costs when prices spike. This does not create a strong incentive for the utility to look for ways to reduce its spending on fuel or shift its generation mix away from price-volatile resources.

Two levers that regulators can employ to encourage better fuel-cost management are fuel-cost sharing and economic dispatch.

Fuel-Cost Sharing

Lever definition: Fuel-cost sharing encourages a utility to find ways to reduce its fuel costs by giving it some skin in the game. This is in contrast to traditional fuel-cost pass-through mechanisms, in which customers bear the entire risk of fuel-price volatility and the utility does not benefit financially from reducing either the amount of fuel it uses or the prices it pays for that fuel. Fuel-cost sharing works by essentially giving the utility a budget for fuel costs. If the utility exceeds that budget, investors have to absorb some percentage of the overruns. If the utility operates under the budget, the investors get to keep a percentage of the savings.

How this lever supports cost containment: When an electric utility's fuel costs are completely passed through to its customers, those costs are typically recovered via a type of cost tracker called a fuel-adjustment clause. A fuel-adjustment clause works by performing an ex-post true-up to customer rates to collect the exact amount the utility spent on fuel. This means that if fuel costs rise, it is the utility's customers and not its shareholders who pick up the bill. By contrast, a fuel-cost sharing mechanism true-ups less than 100% of the difference between the expected fuel costs (which are typically built into base rates) and the utility's actual costs. Because fuel-cost sharing exposes the utility's shareholders to some of the risk of fuel-cost volatility, it gives the utility a reason to work harder to manage its fuel costs. This can include reducing the price it pays for fuel (e.g., by negotiating harder with fuel suppliers or changing its hedging strategy to manage risk exposure), finding ways to cut the amount of fuel it uses in the near term (e.g., by improving plant efficiency), and reducing its reliance on price-volatile fuels in the longer term (e.g., by shifting its generation portfolio to rely more on price-stable resources).

Implementation tips: Fuel-cost sharing mechanisms can be structured in various ways. Some strategies regulators can use to design an effective fuel-cost sharing mechanism include the following:

^{lxviii} Due to the Winter Storm Uri, a natural gas supply shortage caused market prices in West Texas to soar to over \$100 per million British thermal units (MMBtu), a dramatic increase compared with the average of \$3/MMBtu in the week prior. For more details, see Morgan Evans, "Uri Fallout Sent Natural Gas Spending for Electricity Sky-High in 2021; Inflation Piled on Last Year," *Natural Gas Intelligence*, February 16, 2023, <https://naturalgasintel.com/news/uri-fallout-sent-natural-gas-spending-for-electricity-sky-high-in-2021-inflation-piled-on-last-year/>.

- **Learn from states that have long implemented fuel-cost sharing.** At the time of publication, nine states have implemented fuel-cost sharing for electric utilities: Hawaii, Idaho, Missouri, Montana, Oregon, Vermont, Washington, Wisconsin, and Wyoming.^{lxix} In 2024, Colorado passed authorizing legislation, and the state utility commission was working on drafting rules to implement fuel-cost sharing in that state. Each of these states have implemented different flavors of fuel-cost sharing, so looking to them could help inform how regulators can craft a mechanism that is right for their state.
- **Establish the sharing percentage according to the utility's fuel mix.** One of the key determinants in setting the fuel budget is the expected price of fuel. Fuels with stable prices impose less uncertainty on budgets than fuels with volatile prices. Thus, if a utility is reliant on energy sources with stable prices (e.g., coal, nuclear, non-fuel renewables), it is more likely the utility will be able to operate within its fuel budget; in this case, a large sharing percentage (e.g., 20%) may make sense. By contrast, if the utility is reliant on energy sources with volatile fuel prices (e.g., natural gas), even a small sharing percentage (e.g., 5%) could translate into significant financial impacts for the utility and thus be sufficient to motivate it to reduce its fuel costs.
- **Employ historical data or independent forecasts rather than utility forecasts to set the fuel budget.** Because the sharing percentage applies only to the difference between the expected and actual fuel costs, an expected value must be determined by the regulator. This value can be based on either a forecast or historical data. Although forecasts are commonly used to set the fuel budget in fuel-cost sharing mechanisms, they can encourage gaming because a utility can benefit financially by inflating either the forecasted load or the fuel price. Basing the expected value on historical data can avoid this problem, but historical values might not be indicative of future prices. If forecasts are used, the risk of gaming can be reduced by benchmarking against other utilities or by using public or third-party forecasts.
- **Consider different design options.** Fuel-cost sharing mechanisms can employ a single sharing percentage or a banded design (in which the sharing percentage changes when the deviation between the expected and actual fuel costs crosses a particular threshold). They can also be symmetrical (i.e., the sharing percentage can be the same whether fuel costs are higher or lower than expected) or asymmetrical. They can also vary in other ways. Considering different possible designs can enable a PUC to select the one that best supports local policy goals.

Further reading

- For more information about the history of fuel-adjustment clauses, how fuel-cost sharing mechanisms can improve utility incentives, and how advocates can support reforms, see Albert Lin, Jeremy Kalin, and Kaja Rebane, *Learning to Share: A Primer on Fuel-Cost Pass-Through Reform*, PSS Finance Lab, 2023.
- For further reading about both fuel-cost sharing and other strategies to reduce fuel costs, as well as guidance for regulators on fuel-cost sharing mechanism design and real-world examples, see Kaja Rebane et al., *Strategies for Encouraging Good Fuel-Cost Management: A Handbook for Utility Regulators*, RMI, 2023.

^{lxix} Details on the designs of these mechanisms can be found the PIMs Database, RMI, <https://rmi.org/pims-database/>.



Economic Dispatch

Lever definition: Electric utilities that own generation are generally expected to dispatch plants in merit order so that the least-cost capacity is brought online first. However, some utilities that own aging coal plants run those plants even when more cost-effective alternatives are readily available on the grid. Requiring utilities to bring their generation capacity online in merit order — a process known as economic dispatch — can address this problem.

How this lever supports cost containment: Customers in many jurisdictions across the country overpay for electricity because utilities dispatch their generation assets uneconomically.^{lxx} For example, one analysis showed that customers nationwide could have saved \$10 billion between 2016 and 2022 if utilities had followed economic dispatch practices, and customers of one particular utility could have saved as much as \$200 per year if their utility had switched to economic dispatch.³² Regulators can reduce this unnecessary cost burden by requiring utilities to employ economic dispatch.

Implementation tips: To help ensure that utilities dispatch generation resources efficiently, regulators may wish to consider the following actions:

- **Enhance transparency.** Determining whether a utility is dispatching its resources in merit order requires access to utility data (e.g., operating costs, fuel costs, market prices, operating revenue forecasts, and plant-level operating constraints). To facilitate regulatory oversight and ensure that utilities are making prudent operating decisions, PUCs can institute filing

lxx For example, in the MISO region, customers have borne more than \$1 billion in excess costs from the uneconomic dispatch of coal plants between 2021 and 2023. See Zach Zimmerman et al., *The Consumer and Environmental Costs from Uneconomically Dispatching Coal Plants in MISO*, Grid Strategies and Natural Resources Defense Council’s Sustainable FERC Project, 2024, <https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies-NRDC-Uneconomic-Dispatch-Report-2024.pdf>.

requirements that direct utilities to share the necessary cost and operations data on a regular basis. Making this data available to consumer advocates and other stakeholders (subject to sensible nondisclosure requirements where needed) can increase scrutiny of the materials and help alert the PUC to potential issues that should be investigated further.

- **Open an investigatory docket.** Another step a PUC can take is to open an investigatory docket to evaluate the utility's current and past dispatch practices, consider whether they could be improved, and identify possible changes for further exploration. Depending on what the investigation reveals, the PUC can then consider additional dockets as needed to implement any identified changes.^{lxxi}
- **Disallow imprudently incurred costs.** If the utility is found to have engaged in uneconomic dispatch, customers should not be expected to pay for the higher-than-necessary costs that result. In these cases, regulators can deem the excess costs imprudent and disallow cost recovery (or require utilities to issue refunds if customers have already paid for the costs via rates).^{lxxii}

Further reading

- For an analysis of the costs that uneconomic plant operation imposes on the Midcontinent Independent System Operator (MISO) region of the United States, see Zach Zimmerman et al., *The Consumer and Environmental Costs from Uneconomically Dispatching Coal Plants in MISO*, Grid Strategies and Natural Resources Defense Council's Sustainable FERC Project, 2024.
- For in-depth discussion of uneconomic coal-plant dispatch and analysis of its impacts on several US regions, see Joe Daniel et al., *Used, But How Useful? How Electric Utilities Exploit Loopholes, Forcing Customers to Bail Out Uneconomic Coal-Fired Power Plants*, Union of Concerned Scientists, 2020; and Jeremy Fisher et al., *Playing with Other People's Money: How Non-Economic Coal Operations Distort Energy Markets*, Sierra Club, 2019.
- For an interactive data dashboard that tracks the uneconomic operation of coal plants and the impacts on affordability and emissions, see "[Economic Dispatch Dashboard](#)," Utility Transition Hub, RMI, accessed November 22, 2024.

lxxi For example, the Minnesota PUC opened an investigatory docket specifically to explore how the state's utilities dispatch their coal plants. The PUC uses the docket to collect standardized hourly operations data from utilities and to explore opportunities for more economically efficient operations, which has included transitioning coal plants to operate seasonally rather than year-round. See Docket No. E999/AA-18-373, "Order Accepting 2017-2018 Electric Reports and Setting Additional Requirements," Minnesota PUC, November 13, 2019, <https://www.edockets.state.mn.us/documents/%7BF06B666E-0000-C415-9F04-7AC0175405AE%7D/download>.

lxxii For example, the Michigan Public Service Commission disallowed cost recovery for Indiana Michigan Power Company, finding that the utility's uneconomic dispatch of generation resources resulted in imprudently incurred costs that should not be passed on to customers. For details, see Docket No. U-20805, "In the Matter of the Application of Indiana Michigan Power Company for a Power Supply Cost Recovery Reconciliation Proceeding for the 12-Month Period Ended December 31, 2021," Michigan Public Service Commission, October 6, 2020, <https://mi-psc.my.site.com/s/case/500t000000VLY1oAAH/in-the-matter-of-the-application-of-indiana-michigan-power-company-for-a-power-supply-cost-recovery-reconciliation-proceeding-for-the-12month-period-ended-december-31-2021>. Similarly, the Louisiana Public Service Commission disallowed cost recovery for Cleco Power LLC and Southwestern Electric Power Company. The commission determined that the utilities' operation and dispatch of the Dolet Hills Power Station and associated lignite mines from 2019 to 2021 were imprudent, leading to unjust and unreasonable rates. For more, see Docket No. U-35753, "Cleco Power LLC and Southwestern Electric Power Company, ex parte," Louisiana Service Utilities Commission, October 14, 2020, <https://lpscpubvalence.lpsc.louisiana.gov/portal/PSC/DocketDetails?docketId=20141>.

Conclusion

Given the significant changes the electric industry is facing, cost-efficient spending will be of key importance to ensure affordability in coming years. One of the primary ways PUCs can support affordability is by adopting reforms that promote utility cost control.

The strategic framework presented in this report tackles this challenge from multiple angles. It is composed of seven strategies and 16 levers that PUCs, consumer advocates, and other stakeholders can consider for adoption in their local jurisdictions. The framework can be used to evaluate the current regulatory framework's efficacy at supporting cost control, generate ideas for potential reforms, and consider how individual reforms could be combined into an effective policy portfolio.

The levers included in the framework can be supported by complementary reforms that enhance transparency. This is because regulators can perform their oversight role better — and advocates and other stakeholders can more effectively support them in that role — when they have a solid understanding of the grid's needs, as well as the costs and benefits of the options available to the utility to address those needs. However, greater transparency not only means gaining access to more information but also having the context necessary to understand the information available and distinguish between what is important and what is not. A suite of reforms that strengthen transparency through both requirements (e.g., reporting standards) and incentives (e.g., better alignment of utility profit opportunities with customer interests) is likely to have the greatest impact, and thus to best support increased visibility into utility planning, investment, and operations decisions.

Although the strategic framework focuses primarily on utility cost control, this is just one avenue through which PUCs can support affordability. To more comprehensively address the affordability challenge, regulators should also consider reforms that focus on cost responsibility and predictability and customer agency. We therefore encourage regulators and stakeholders to assess the landscape of programs, tariffs, rules, regulations, and laws in place that may work against affordability, and to consider reforms through any of these four avenues.

Access to safe, reliable, and clean electricity is critical to human health and well-being, the financial stability of families, and local economies — and the importance of electricity is only growing as our society becomes more digitized and interconnected. PUCs' efforts to ensure that utility rates are affordable are therefore more important than ever. We hope the addition of this strategic framework for cost control to regulators' toolkit will suggest new ideas, stimulate fresh conversations, and help PUCs across the country to adopt reforms that support affordability through the clean energy transition.

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