Performance-Based Regulation

Harmonizing Electric Utility Priorities and State Policy

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Overview

The electricity sector is experiencing a period of substantial transformation. New technologies, changing consumer behavior and government policies are creating financial challenges for utilities and changing the ways they operate, interact with customers, make money and plan for the future. These dynamics have led a growing number of states to consider whether utility regulatory practices should evolve to better address this new operational environment.

Under traditional regulatory approaches, which originated more than a century ago, utilities may lack strong financial incentives to contain costs and pursue initiatives that better align with current consumer demands and state policy goals. These structures may also lack the flexibility required to meet emerging challenges as the grid evolves to accommodate new resources, optimize operations and enable greater consumer participation through new services and technologies.

Those limitations have led legislatures in at least 17 states and Washington, D.C., to enact policies that open the door to regulatory reforms designed to encourage better utility performance. These alternative practices—broadly referred to as "performance-based regulation" or "PBR"—have been developed to reduce regulatory costs and foster a more symbiotic relationship between a utility, its customers and the jurisdiction in which it operates.

Performance-based regulation can come in many different forms, but its principal goal is uniform: to improve utility performance by shifting the dynamics around how utilities make money.

Utility performance has long been appraised on the basis of cost and reliability. Although these remain bedrock performance concerns for regulators and other policymakers, more recently states have begun to expand on this idea to include new priorities, such as meeting state environmental goals, improving operational efficiency, enhancing reliability, offering innovative services to customers and being more attentive to equity issues. While utilities have traditionally made money based on the cost of providing electricity service to customers, these new frameworks are often designed to provide utilities with financial incentives tied to the utility's performance in these areas.

There is no magic bullet to addressing these issues; performance-based regulation is a concept that requires thoughtful consideration of utility ownership structures, external business conditions, consumer protection and public policy goals. There are a variety of approaches to performance-based regulation—each with its own advantages and challenges—that can be applied individually or in concert.

However, many stakeholders and regulatory experts argue that performance-based regulation has the potential to move electric utilities fully into the 21st century by strengthening cost-containment incentives and aligning electric utility priorities with societal and state policy goals. This primer is designed to provide state legislators with context around these evolving industry dynamics, an overview of the most common performance-based approaches to utility regulation, and an introduction to the state legislatures role in this process.

Terms & Definitions

Attrition Relief Mechanism (ARM): A common element of multiyear rate plans that automatically adjusts rates or allowed revenue between rate cases to provide for revenue acceleration without tracking the utility's direct costs.

Authorized Return on Equity (ROE): The state utility regulatory commission (PUC) approves a rate of return—a percentage of the value of equity capital invested—that shareholders of an investor-owned utility earn as profit.

Base Rates: The components of a utility's rates that address the costs of non-energy inputs, including labor, materials and capital.

Cost-of-Service (COS) Regulation: The traditional approach to regulating utilities in the U.S., which resets utility rates during periodic rate cases before state PUCs to recover the cost of providing service to customers.

Cost Tracker: A mechanism providing expedited recovery of certain costs between rate cases. Trackers are most commonly used to address fuel and purchased power expenses, which are typically recovered through riders on customer bills.

Distributed Energy Resources (DERs): Technologies, services and practices that are sited at or near the distribution grid. DERs can include energy storage systems, electric vehicles and generating technologies, including rooftop solar, microturbines and combined heat and power. They can also include demand-management services and practices, such as demand response and energy efficiency.

Earnings Sharing Mechanism (ESM): A mechanism designed to share surplus earnings or deficits between utilities and customers when the ROE deviates significantly from the approved target.

Lost Revenue Adjustment Mechanism (LRAM): A mechanism designed to compensate utilities for lost revenue resulting from DERs growth and demand-side management practices that reduce utility sales.

Marketing Flexibility: When some forms of PBR permit regulators to grant utilities flexibility in rate designs and services they offer in certain markets. This can come in the form of innovative pricing plans and services to advance priorities, incentivize new technologies or pursue underutilized practices.

Multiyear Rate Plans (MYRPs): A common approach to performance-based regulation (PBR) that features a multiyear rate case moratorium and an attrition relief mechanism to escalate revenue between rate cases. MYRPs are often coupled with other PBR approaches, such as performance incentive mechanism or performance metrics tracking.

The Origins of Electric Utility Regulation

The traditional regulatory framework—known as "cost-of-service" (COS) regulation—was developed throughout the 20th century, during a period of substantial growth in demand as access to electricity went from a novelty to a necessity throughout the United States and much of the world. As a result, the primary objective was to continually and progressively expand service to new customers. COS regulation helped accomplish those goals by establishing a predictable regulatory framework that enabled utilities to make the desired investments with confidence they would recover the full cost of providing service, including a reasonable return on equity.

Electricity is an essential service. It is considered vital to the health, safety and economic productivity of society. Like other essential service providers, the electric sector has been subject to government oversight. The infrastructure required to provide electric service also led to the early determination that electric utilities are "natural monopolies"—industries in which a single entity can serve a market at a lower cost than any combination of two or more entities, often due to high startup costs and economies of scale.

Off-Ramp Mechanism: A mechanism designed to allow for the suspension or reconsideration of an MYRP based on pre-specified conditions, such as extreme underearning or overearning.

Performance-Based Regulation (PBR): An approach to utility regulation designed to strengthen utility incentives to improve performance and align utility priorities with those of customers and public policy.

Performance Incentive Mechanism (PIM): Metrics, targets and financial incentives designed to improve utility performance in targeted areas.

Rate Base: The net value of a utility investment to provide service, such as building a new generating resource, including the accumulated depreciation on that investment.

Rate Case: A proceeding before a state PUC that includes a review of the utility's costs in order to reset rates to recover the prudent cost of providing service.

Rate Rider: A mechanism specified in a utility tariff that allows for supplemental revenue adjustments.

Revenue Requirement: The annual revenue that a state PUC has approved a utility to collect. The amount is periodically recalculated through rate cases and may be adjusted between rate cases through mechanisms like cost-trackers and ARMs. This is calculated by subtracting other operating revenues from a combination of operation and maintenance expenses, depreciation, taxes and a return on rate base.

Revenue Regulation/Decoupling: A rate adjustment mechanism designed to break the link between utility sales and revenue, thereby reducing a utility's incentive to increase sales between rate cases.

Shared Savings Mechanism (SSM): This mechanism allows utilities and ratepayers to share in the financial benefits realized through programs like energy efficiency.

Throughput Incentive: Under some regulatory approaches—including cost-of-service regulation—utilities have an incentive to increase sales between rate cases to increase revenue. This occurs because utilities recover the cost of both invested capital and operating expenses in rates charged to customers, which are set in rate cases. If a utility increases its sales between rate cases, that will often result in higher revenue because the cost of providing more electricity is normally less than what customers are paying.

This determination led to the establishment of many vertically integrated utilities, which had a franchised monopoly over all sectors of the industry within their service territory. These utilities owned and operated everything from the power plants to the meter on a customer's home. For much of the industry's history, this was the default utility business model.

The electric industry has been regulated by federal, state and local entities under these principles. Often referred to as the "regulatory compact," a utility accepts an obligation to provide a public service and subjects itself to government oversight in exchange for guaranteed revenue that will fully compensate the utility for the prudently incurred costs of providing that service. In practice, COS regulation allows regulated utilities the opportunity to recover substantially all of the costs they incur, including an authorized rate of return on investments through electricity rates paid by customers.

State utility regulators—referred to in this report as state public utility commissions (or state PUCs)—oversee retail utility rates and services with a dual mandate: to ensure that customers have reliable and safe access to electricity at just and reasonable rates. PUCs approve retail rates through proceedings called "rate cases" to create the opportunity for a utility to recover its operating and capital costs, including a return on capital expenditures. Capital expenditures on infrastructure—such as investments in new power plants or substations—require PUC approval. Rates are set to recover the revenue requirement from customers.

For a detailed discussion on electric sector restructuring and the development of electricity markets, please see NCSL's "Electricity Markets: A Primer for State Legislators."

Once approved, utilities earn a return on these investments, often regardless of whether a project costs more than predicted. In some cases, PUC prudency reviews have resulted in cost disallowances and a reduction in the allowed rate of return due to mismanagement or imprudent expenses.

This form of regulation—grounded in the desire for growth—has dictated utility business models for decades by establishing clear incentives for utilities to maximize sales and capital expenditures on infrastructure to increase profits.

Cost-of-Service Regulation: Incentives & Limitations

It's often noted that regulated entities respond to the incentives they're provided by regulators. The COS framework comes with several inherent incentives for regulated utilities, most of which evolved from the era when expanding service was a driving motivation.

The majority of utilities in the U.S. still operate under COS regulation. This regulatory framework affects utilities of all types and structures—from investor-owned utilities to customer-owned, in states with vertically integrated utilities and those that restructured their electric sector to enable greater competition in power supply.

The COS regulatory framework allows a utility to petition the PUC for rate adjustments through rate cases to compensate the utility for changes to the cost of providing service. Large variable costs, including the cost of fuel and purchased power, are commonly tracked. As part of the proceeding, the PUC approves an allowed rate of return on equity for the utility; that return on equity is earned on all investments included in the rate base. These costs are ultimately borne by the utility's customers—with the rate base and trackers all translated into monthly bills paid by customers.

At its simplest, a rate case is a proceeding in which a utility provides regulators with information detailing a variety of historical and projected costs to justify how much its customers will be charged. However, a rate case also establishes the operating parameters for a utility's business model—including the parameters that dictate utility earnings.

Under this construct, the utility has two primary pathways to increase earnings:

1) **Capital expenditures:** The utility is allowed to recover all capital costs, along with a small profit, creating a financial incentive to pursue capital projects.

2) **Electricity sales:** Under traditional rate designs with high usage charges, the utility can usually increase profits by increasing sales.

This structure, with its incentives to pursue capital projects and increase sales, provides utilities with a significant degree of operational and financial certainty. It's allowed for universal service in the U.S. and has made utilities safe and reliable investments for shareholders.

However, critics of the COS model argue that it shifts too much of the risk for capital projects onto customers and fails to incentivize the types of cost-saving strategies and demand-side management measures needed today to avoid unnecessary capital spending and encourage more efficient use of energy. Cost containment incentives are weak, while regulatory costs are high when rate cases are frequent. Research from Lawrence Berkeley National Laboratory determined that utilities operating under COS regulation have a material disincentive to pursue demand-side management strategies or to accommodate distributed energy resources (DERs), even when DERs meet customer needs at a lower cost than traditional options. That is because these strategies and technologies—including energy efficiency, rooftop solar, energy storage and demand response—effectively reduce usage, thereby reducing electricity revenue. In some cases, they may also reduce the need for traditional capital projects—a concept known as "non-wire alternatives."

The argument isn't that COS regulation is inherently problematic, rather that it was designed for a different business environment and set of public policy goals than the electric industry faces today.

Different Dynamics, Different Incentives

The electric sector is now experiencing the greatest upheaval in the last half-century. The changes, driven by a variety of factors, have caused utilities and policymakers to rethink the status quo.

COS regulation has worked for so long, in part, because electric demand was continually growing. The external business conditions, coupled with the political prerogative, supported this approach. Utilities have the operational and financial surety of a regulatory model that usually makes them whole as they work to serve a rapidly growing customer appetite.

However, business conditions have changed in recent decades, leading to more financial uncertainty and more frequent rate cases, which increases regulatory costs and weakens cost-containment incentives. Two of the primary factors have been a combination of accelerating cost growth—due to high capital expenditures and, more recently, inflation—and slowing revenue growth due to relatively stagnant demand. There are a number of additional factors driving the change, much of which revolves around technological advancements, societal mandates and economics:

- **Flattening growth:** Retail electric sales have grown at much slower rates over the past decade, undercutting the COS model's primary incentives. This has led to more frequent rate cases and an increase in the cost of regulation. Electricity sales are projected to grow again over the coming decades as transportation and building electrification efforts increase demand for electricity, which triggers concern over excessive capacity expansion.
- **Technological advances:** The rapid advancements in smart grid technology, renewable energy, energy storage and demand management practices have turned the traditional model of grid operations on its head. On the bulk power grid, baseload power plants are retiring, replaced in many cases by renewable generation that requires more responsive, flexible resources to ramp up and down based on variable output. Meanwhile, the management of the distribution grid is changing, with distributed generation—including customer-sited resources—and demand management measures affecting how utilities plan and operate the distribution grid.
- **Lowest cost options:** There are now lower-cost alternatives to capacity expansions for addressing both customer and system needs. These include "non-wire alternatives" to major capital projects and demand management strategies, like energy efficiency and demand response.
- **Public policy goals:** Societal mandates, through public policy, have asked much of the utility sector over the past decade. Previously, state regulators had two primary concerns: ensuring that utilities provided customers with safe and reliable service at the lowest possible cost. However, states have established many more policy goals in recent years. Some of these goals include the deployment of renewable and clean energy, reducing emissions, enhancing resilience against extreme weather, increased system efficiency, introducing elements of competition into the sector, encouraging the growth of innovative new technologies and addressing energy equity.

- **External Cost Pressures:** In addition to higher costs for things like decarbonization strategies and smart grid technologies, utilities have experienced various external cost pressures that include increasingly severe weather events, the need to replace aging infrastructure and, more recently, a rapid rate of inflation.
- **Customer behavior:** Smaller customers, including residential and small commercial, are no longer passive consumers; they are increasingly active participants who want new services to help them manage, optimize, and reduce their energy use and provide services to the grid through demand management and customer-sited distributed generation.

Given that utilities respond to the regulatory incentives they're provided, legislators in at least 17 states and Washington, D.C., have reconsidered their approach to utility regulation to better align utility operations with incentives to contain costs, meet policy goals and adjust to changing industry dynamics.

New Regulatory Frameworks

The maelstrom of changing business conditions described in the preceding section has triggered interest in finding alternatives to traditional regulatory frameworks. The most commonly used phrase to describe these new regulatory frameworks is "performance-based regulation" (PBR). The idea behind PBR is to establish a regulatory framework with stronger financial incentives for utilities to deliver on specific goals, targets or performance measures. In doing so, PBR can be used to align utility priorities with those of their customers and public policy.

To accomplish this, PBR frameworks require careful consideration and planning. Topic experts acknowledge there is no one-size-fits-all approach. The exact mechanisms deployed successfully for a publicly owned and vertically integrated utility may not work effectively for an investor-owned distribution utility in a restructured state. With that said, PBR—in some form or another—has been applied to utilities of all stripes and colors.

PBR mechanisms can be applied incrementally to supplement traditional COS regulation aimed at tracking or improving utility performance in certain areas, or to soften COS incentives, such as by breaking the link

Utility Ownership Structures

There are more than 3,300 electric utilities in the U.S., but three primary models of utility ownership.

Investor-Owned Utilities (IOUs): Private, for-profit companies subject to rate and service regulation and financed by shareholder equity and bondholder debt. Around three-quarters of the U.S. population is served by IOUs, which are interested in providing a high, stable rate of return for shareholders. Retail services of IOUs fall under state PUC jurisdiction; most state policies to implement PBR are focused on IOUs.

Public Power and Municipal Utilities: Publicly owned utilities, often owned and operated as semi-autonomous government agencies tasked with providing public services. Rates and services of these utilities rarely fall under the regulatory jurisdiction of state PUCs; they are often self-governed by a board. As public entities, they are more likely to have political or societal objectives and borrow through bonds.

Electric Cooperatives: Situated primarily in rural areas, electric co-ops are private, customer-owned nonprofit entities. State PUCs rarely have regulatory oversight of the rates and services of co-ops, which are overseen by a board of customer representatives.

between electricity sales and utility revenue. At the other end of the spectrum, several states and jurisdictions are pursuing comprehensive new regulatory frameworks that combine multiple PBR mechanisms to change the utility business model more substantially—in some cases, tying utility earnings more directly to improving performance and away from the rate base.

Most of these new regulatory frameworks are enabled through state legislation and implemented by state PUCs. At least 17 states and Washington, D.C., have enacted legislation that either opens the door to PBR or requires utilities to operate under this new regulatory structure. Several states, including New York, have pursued PBR through administrative or regulatory proceedings without explicit legislative direction. While many of these states have prioritized PBR for electric utilities, at least seven states have also included natural gas utilities.

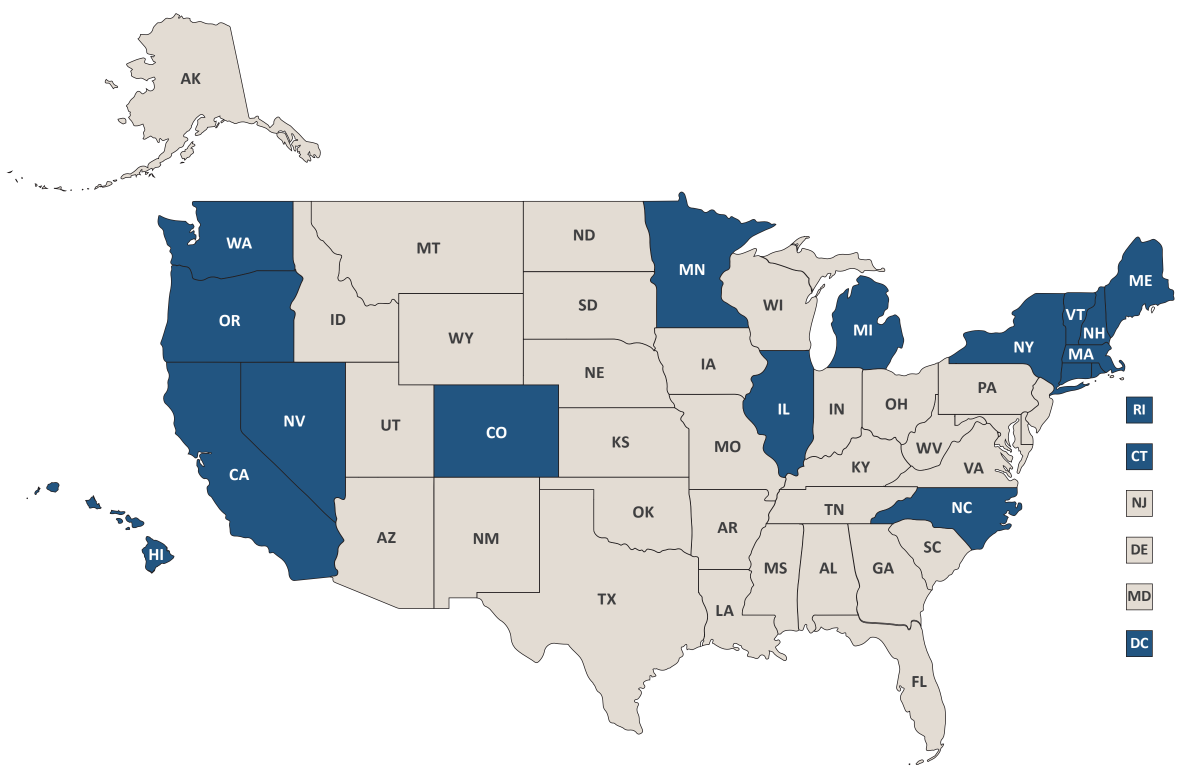
The nature of state legislation and regulatory approach can vary considerably between states. In many cases, utilities and regulators are moving methodically and cautiously. Incremental changes are common to avoid unanticipated changes to utility earnings or customer bills, and to gauge the efficacy of various approaches.

In some states, lawmakers have simply opened the door to explore PBR; they allow utilities to propose PBR mechanisms before state PUCs, but leave it up to the utility to take those steps and walk through the door. In other states, utilities are required to propose certain approaches to PBR during rate cases.

However, several states—including Hawaii, Illinois, Massachusetts and New York—have taken more substantial action to transition regulated utilities to performance-based regulation by requiring utilities and state PUCs to implement PBR approaches.

> "In all jurisdictions, utilities enable achievement of important societal goals. Performance-based regulation is regulation in which anyone can know how good utilities are at delivering on clearly stated expectations and, in its higher form, where management is strongly motivated to deliver on public goals as well as internal and fiduciary goals."

– Regulatory Assistance Project, Next-Generation Performance-Bbased Regulation, Vol. 1



Performance-Based Regulation

Performance-based regulation is not a single approach to regulation, so much as a set of overlapping approaches to improve utility performance. PBR has been around in the U.S. electric sector since the 1980s and gained traction in the 1990s among states such as Massachusetts and California that restructured their electricity sector. At the time, the primary focus was to increase cost efficiency, reduce customer bills and streamline regulation.

However, over the ensuing decades PBR has evolved. While cost containment and reliability continue to be central drivers in PBR, the focus has expanded. Utilities are being pushed to address a variety of new priorities—driven often by public policy and their own customers. Many of these new priorities are tied to broader social mandates and newly available technologies. Some of the new areas of focus include:

- Meeting renewable, clean energy or emissions-reduction goals.
- Encouraging new technologies, including DERs and smart grid technologies.
- Improving operational efficiency through demand-side resources.
- Enhancing reliability and resilience.
- Addressing issues related to energy equity.
- Offering innovative rates and services to customers and improving customer satisfaction.

In designing a PBR framework, it's important for policymakers to consider and understand the ownership structure of the utility, the financial and management structure, and how the utility maximizes its revenue and profit. In most states, only investor-owned utilities fall under the jurisdiction of state PUCs—and therefore state legislation implemented by state PUCs. That leaves states with little regulatory oversight of consumer-owned utilities, including municipal utilities and electric cooperatives.

Different types of utilities have different motivational drivers that will determine how they respond to incentives under PBR. These considerations will affect the exact approach that a state may take in implementing PBR to ensure that utility owners and customers share in the benefits.

There are four primary approaches to PBR that have evolved over the preceding decades:

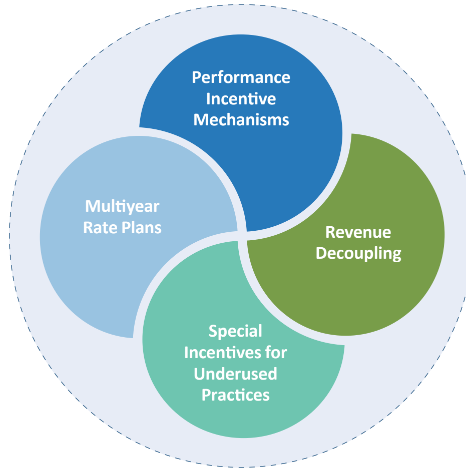
Revenue Decoupling: A rate adjustment mechanism intended to reduce the "throughput incentive" that's present in COS regulation, by which utilities may have an inherent incentive to increase sales in order to increase revenue. Revenue decoupling is a mechanism that authorizes allowed revenues separate from utility sales and periodically adjusts rates to ensure actual revenues match allowed revenues.

Performance Metrics and Incentive Mechanisms: Clear and measurable metrics—including some linked to targets and incentives—used to monitor and incentivize performance in priority areas.

Multiyear Rate Plans: Intended to streamline the regulatory process, strengthen cost-containment incentives and provide utilities with greater operational flexibility, these plans combine a multiyear rate case moratorium with a mechanism that automatically adjusts utility rates between rate cases to account for drivers of financial attrition without being tied to actual costs.

Incentives for Underused Practices: Cost-trackers and other financial incentives may be used to encourage utilities to pursue solutions that may be innovative but beyond the utility's normal appetite for risk. In other cases, utilities may avoid these solutions or practices to bolster capital revenue.

These approaches are by no means mutually exclusive. In fact, PBR is often a combination of multiple approaches and policies blending into a unique PBR framework. Each element serves to address various limitations with the COS regulatory model and, in concert, form the basis for a new utility business model designed to reward utilities for improved performance. The following sections explore each of these approaches in more detail.



Performance-based regulation (PBR) often relies on a combination of approaches.
Source: Pacific Economics Group Research, LLC

For a detailed discussion on how ownership structures and other institutional arrangements affect PBR design, NCSL recommends reading the Regulatory Assistance Project's "Next-Generation Performance-Based Regulation, Vol. 2."

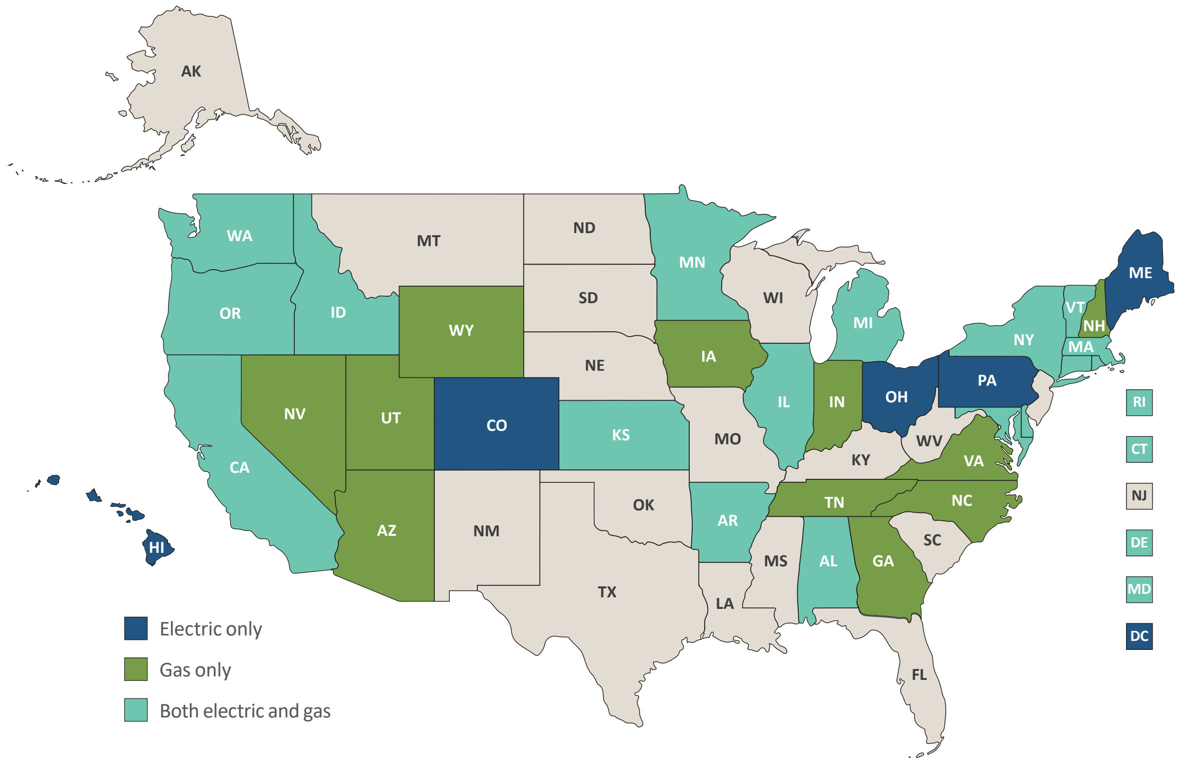
Revenue Decoupling

Revenue decoupling—sometimes referred to as "revenue regulation"—is the most widely used mechanism for removing the incentive for utilities to increase sales in order to increase earnings. In doing so, utility revenue no longer depends on consumption, thereby removing disincentives for utilities to pursue rate designs and programs that encourage demand-side management or enable customers to integrate distributed energy resources (DERs). At least 33 states and Washington, D.C., have adopted decoupling policies; 17 of those states adopted policies for both electric and natural gas utilities.

In practice, decoupling is a rate adjustment mechanism that breaks the link between sales and revenue by adjusting rates to ensure that utilities recover no more or no less than their allowed revenue—an amount that, based on historical data, should be sufficient for utilities to recover their fixed costs and earn a small rate of return. Decoupling price adjustments are used to reconcile actual and allowed revenue.

More broadly, decoupling removes a disincentive for utilities to embrace energy efficiency or other demand-reduction measures by providing greater assurance that rate designs or programs that reduce sales won't jeopardize recovery of their fixed costs—expenses that don't change based on electricity consumption, such as investment, labor and investor earnings. Under decoupling, the utility's financial risk may decrease as a result of the flexibility afforded by the policy. By softening the throughput incentive, utilities also have more flexibility to address system needs outside of capital expenditures, which reduces capital costs.

Decoupling policies have been in place in many states for decades. Policies can vary in three primary ways: how broadly the policy is applied; how revenue adjustments are structured; and how to address a revenue surplus or deficits.



- **How the policy is applied:** Decoupling policies can be applied to a single or multiple utility functions, such as generation, transmission or distribution services. Similarly, the revenue adjustment can be designed as a reconciling mechanism to allow for full, partial or limited reconciliations. While limited decoupling only allows for adjustments under pre-defined conditions, full decoupling allows utilities to fully recover allowed revenue.
- **How revenue adjustments are structured:** The structure of the revenue adjustment mechanism can also vary. In most states, revenue is adjusted automatically between rate cases, while a few don't allow such adjustments. Given the costs associated with rate cases, many states have opted for the former and adopted various mechanisms to automatically adjust revenue based on factors like customer growth.
- **How to address revenue surplus or deficits:** The reality is that actual revenue and allowed revenue are rarely equal. This means that either the utility is underearning or overearning. Most often state PUCs apply rate adjustments to account for these deviations—either crediting or debiting customers as necessary. In some cases, to provide an added incentive for efficiency, these policies will allow utilities to retain a certain percentage of over-earnings.

Given the various flavors of decoupling, this approach can be tailored to meet policymakers' and utilities' needs—whether incorporated into a traditional regulatory framework to remove a disincentive for utilities to decrease sales as a result of demand-side reductions or as part of a broader PBR structure with utility earnings tied more directly to specific performance incentives.

Alternatively, some states have used Lost Revenue Adjustment Mechanisms (LRAMs) to incentivize energy efficiency or other initiatives that result in reduced electricity sales. LRAMs allow utilities to recover lost revenue specifically from state PUC-approved energy efficiency or demand-side management programs that result in reduced sales. While the goals are similar, decoupling tends to be a more comprehensive and effective approach.

It's worth noting that while decoupling removes a disincentive for utilities to decrease sales as a result of programs that reduce demand, it does not establish a positive incentive for utilities to pursue those same programs rather than invest in capacity expansion. Effective policies to incentivize programs that advance demand-reduction priorities often combine revenue decoupling with specific performance incentive mechanisms, known as PIMs, that provide the opportunity for utilities to benefit financially from a successful program.

Therefore, many states do implement decoupling as part of broader PBR packages, with PIMs designed to create a positive incentive for the utility to pursue energy efficiency or demand management programs. Decoupling and PIMs often work best in tandem; each mechanism enhances the effectiveness of the other.

For a more detailed discussion on revenue decoupling policies, please read NCSL's report, "State Policies for Utility Investment in Energy Efficiency."

Performance Metrics and Incentive Mechanisms

Performance incentive mechanisms (PIMs) are one of the primary approaches to align utility motivations with desired outcomes. PIMs are ratemaking mechanisms that tie some portion of a utility's revenues or earnings to its performance in a certain target area, based on measurable customer, utility system or public policy outcomes. The regulatory approach in this area typically includes tracking performance metrics, establishing performance targets and designing clear financial incentives for utilities to strengthen performance in certain areas. Some metrics may be tracked without incentives to provide tracking insight for regulators, customers and policymakers.

PIMs are also highly versatile. They have been incrementally applied to traditional COS regulatory frameworks, allowing regulators to address a few key performance areas within the existing regulatory construct. PIMs have also been used in more comprehensive PBR efforts to link utility profits more directly with performance across a suite of targeted areas, such as New York's Reforming the Energy Vision strategy.

In every case, they are intended to shift the regulatory focus toward utility performance outcomes through the use of metrics. Tracking utility performance through data on a handful of metrics—known as "tracking metrics"—can be an early step toward increasing transparency and establishing PIMs. On the intermediate side, the state PUC may establish a target or goal and measure the utility's performance in relation to that goal. The implementation of tracking and reporting metrics is straightforward and low-risk, and can

be done in a way that adds little administrative burden to either regulators or utilities, while delivering valuable information. In some cases, tracking metrics—without any explicit target or incentive—can provide information that alters utility practices to achieve a desired outcome. They can also be a useful entry-level tool that provides regulators and utilities with practical experience reporting and tracking metrics related to innovative approaches or new areas of focus, without the potential risks that come with targets or incentives.

PIMs can be designed in a variety of ways, but the central idea is to tie utility earnings to the utility's performance in specific areas that advance customer or broader societal goals. In doing so, the utility has a bigger stake in the game—a true financial imperative to deliver on those goals.

PIMs also clarify regulatory priorities. Utility goals and incentives are explicit; PIMs allow regulators to identify key areas for utility improvement, clearly enumerate those goals and include direct incentives for utilities to meet those goals or penalties when they do not. State regulators can use PIMs to provide utilities with clear regulatory guidance on state policy goals, address emerging issues and improve customer satisfaction.

PIMs have been used for decades to address utility performance in traditional areas of focus, including lowering costs for customers, maintaining reliability, improving customer satisfaction and encouraging energy efficiency. In more recent years, PIMs have been designed to address new areas of focus related to public policy goals, including:

- Meeting renewable, clean energy or emissions-reduction goals.
- Encouraging new technologies, including DERs and smart grid technologies.
- Improving peak-load management.
- Enhancing reliability and resilience.
- Addressing issues related to energy equity.
- Accommodating electric vehicles or other forms of beneficial electrification.

While PIMs have been effectively applied in many scenarios, they are still only as effective as their design and implementation. Careful consideration is required to ensure that rewards and penalties are proportionate, in the public interest and not able to be gamed or manipulated. They can also add to the cost of regulation by requiring onerous tracking and oversight for utilities and regulators.

However, thoughtful policy design, regulatory flexibility and frequent regulatory review can overcome these hurdles.

For a detailed discussion of performance incentive mechanisms, NCSL recommends reading Synapse Energy Economics, Inc.'s report, "Utility Performance Incentive Mechanisms: A Handbook for Regulators."

Multiyear Rate Plans

Multiyear rate plans (MYRPs) are another common approach to PBR that have been utilized to strengthen cost containment incentives and reduce regulatory burdens that come with frequent rate cases. Under an MYRP, regulators approve a multiyear plan that establishes a revenue requirement necessary to cover the anticipated cost of providing service over that timeframe.

This approach has been used since the 1980s in various industries. It is now used for distribution and vertically integrated utilities in various parts of the U.S. A key issue for regulators and legislators to consider is whether frequent rate cases are a growing problem and, if so, whether the MYRP approach is the preferred solution.

MYRPs are typically pursued to establish utility cost containment incentives, to reduce regulatory costs and burdens, and to encourage innovation by enabling utilities greater flexibility in how they manage business decisions. With stronger performance incentives, utility actions are more likely to be prudent, allowing regulators to grant flexibility. In concert, strong incentives and greater flexibility encourage innovation. This can shift the utility's focus away from increasing sales to accelerate revenue growth and toward achieving cost reductions, because the utility is often permitted to keep some or all of the savings from these initiatives.

Multiyear Rate Plans vs Formula Rates

It's important to distinguish between MYRPs and formula rates. While both approaches use formulas, they are not the same and have been misconstrued.

MYRPs use an attrition relief mechanism to establish an allowance for cost growth that is not tied to actual costs. This establishes an incentive for utilities to keep costs within that allowance.

Formula rates establish a mechanism that ensures utility revenues track actual costs directly, often measured as deviations from the utility's approved return on equity. This has been described by as a "wide-scope cost tracker." By ensuring revenue tracks closely with actual costs, the utility's incentive for cost containment is reduced.

MYRPs strengthen utility performance incentives and streamline the regulatory process through two primary elements:

1) **Rate case moratorium:** General rate cases are suspended in favor of defined rate cycles—often once every three to five years. The idea is to reduce the frequency of rate cases and, in doing so, reduce the cost of regulation for the utility, the regulator and other stakeholders.
2) **Attrition relief mechanism (ARM):** A mechanism by which utility rates are automatically adjusted between rate cases to account for sources of financial attrition without being linked directly to the utility's actual cost growth during the course of the plan. In essence, an ARM gives the utility an "allowance for cost growth, rather than reimbursement for its actual cost growth." The ARM is usually based on a combination of cost forecasts and indexes that reflect changes in utility cost drivers, such as inflation, productivity trends and customer growth.

Beyond those two elements, MYRPs can incorporate a variety of additional components and complimentary PBR approaches. According to research from Lawrence Berkeley National Laboratory (LBNL), most MYRPs include performance incentive mechanisms. These typically include PIMs for reliability, customer service quality and conservation, though they may also include cost-benchmarking and policy goals. Many MYRPs also contain one or more of the following elements:

- **Earning sharing mechanism:** A mechanism to ensure that customers share in the utility's surplus earnings or, less commonly, losses.
- **Revenue decoupling or lost revenue adjustment mechanisms (LRAMs):** This rate adjustment mechanism is intended to break the link between utility sales and revenue, thereby reducing the "throughput incentive" that encourages utilities to increase sales.
- **Off-ramp mechanisms:** As a reassurance to multiple parties facing the uncertainty of new regulatory frameworks, off-ramp mechanisms allow for a reconsideration of the MYRP due to extreme variations from anticipated earnings.
- **Incentives for underused practices:** MYRPs may include provisions to encourage utilities to pursue innovative and underused practices, technologies or programs. These may include cost-trackers or other incentives to facilitate demand-side management programs that reduce electricity sales.
- **Marketing flexibility:** The reduction in the frequency of rate cases that MYRPs make possible can reduce concerns about cross subsidies between customer classes and make it easier for the PUC to grant greater marketing flexibility, which enables utilities to offer customers alternative rates and services. These incentives will be discussed further in a subsequent section of this report.

The efficacy of MYRPs stems from the current business conditions facing electric utilities, with flattening demand growth and accelerating cost growth. Under COS regulation, these conditions have, in some cases, led to more frequent rate cases and substantial use of cost-trackers. The appeal of MYRPs is in their ability to provide utilities with operational flexibility while streamlining the regulatory process and reducing costs. According to the LBNL report, regulatory cost savings "of 3-10% after 10 years appear achievable under MYRPs."

This approach is not without its risks. The shift in regulatory approach from COS is significant, and the complexity of the plans require substantial consideration and thoughtful design from state regulators and utilities alike. It's important to safeguard customers during this process, as well, to ensure that benefits are shared among all stakeholders. As with any new policy design, thoughtful attention to safeguards and best practices will be important.

For a more detailed discussion of multiyear rate plans, NCSL recommends reading Lawrence Berkeley National Laboratory's report, "State Performance-Based Regulation Using Multiyeaar Rate Plans for U.S. Electric Utilities."

Incentives for Underused Practices

While the previous approaches to PBR are individually recognizable, the final approach is more of an amalgam of special incentives to try new or underutilized practices. Utilities are risk-averse by nature; a combination of providing a critical service, while also needing to satisfy both shareholders and regulators. But with the energy sector in a dynamic state, some have argued that utilities need to begin embracing the disruption and trying new or underutilized approaches to meet these emerging challenges.

To support innovation, some PBR proceedings have established special cost-trackers for underutilized practices, the capitalization of certain operations and maintenance expenses, or offered a premium allowed rate of return on equity for things like demand-side management programs, distributed energy resources (DERs) and the recovery of stranded costs. Shared savings mechanisms (SSMs) are one example of regulatory incentive to support energy efficiency and other programs that result in reduced consumption. SSMs assess the savings resulting from these programs and shares the savings between the utility and customers.

Some states have also included pilot programs within PBR frameworks to test new technologies and rate design practices. In some cases, these programs are designed to target emerging issues, such as high local penetrations of DERs or peak load management. Flexibility in billing and rate design practices—known as "marketing flexibility"—can be an especially effective tool for demand-side management. Rates can be used to send signals to customers that influence usage patterns and can help manage the distribution grid. State PUCs have enabled—even encouraged—utilities to test out alternative rate designs, such as minimum bills, time-based rates or demand charges. Another practice gaining traction in several states has been to allow utilities to securitize stranded generation assets—generally, fossil fuel-fired power plants—that are retired early as states push utilities to accelerate the clean energy transition. This can accelerate commitments to cost recovery and facilitate utility investments in clean energy technologies.

For a more detailed discussion on how alternative regulation can support distributed energy resources, NCSL recommends reading Lawrence Berkeley National Laboratory's report, "Performance-Based Regulation in a High Distributed Energy Resources Future."

For a more detailed discussion on alternative rate design, please read NCSL's report, "Modernizing the Electric Grid: State Role and Policy Options."

Piecing It Together

The complex nature of utility regulation leaves state legislators in a unique position. On the one hand, state legislation is often a necessary step in enabling state regulators and utilities to implement—or even consider—some of these alternative regulatory approaches. At least 17 states and Washington, D.C., have enacted legislation to enable performance-based regulatory approaches. In many cases, that legislation simply expands the list of ingredients that state regulators can use in a recipe.

On the other hand, the manner in which legislation is implemented will ultimately be the product of complex ratemaking proceedings between state PUCs and utilities. Legislatures may expand the list of potential ingredients—may even require certain ingredients be used—but the cake is truly designed and baked elsewhere.

This dynamic requires legislation that is prescriptive enough to ensure certain outcomes are achieved, while leaving enough flexibility for regulators and utilities to solve for challenges. It's up to legislatures to provide clear guidance and a vision for what type of cake they want. It's the job of state regulators to use their expertise and the available ingredients to design a cake that delivers on the legislature's vision.

This section will review state examples to explore key factors and considerations in developing PBR legislation that aims to strike this balance. While New York's Reforming the Energy Vision (REV) initiative is a leading national example in PBR implementation, it was not driven by legislation and therefore will not be included as part of the following discussion.

ESTABLISHING A FOUNDATION

Reforming a regulatory framework that's been in use for nearly a century is no small matter. The COS regulatory construct developed progressively over decades, with policymakers and utilities continually improving upon the framework when and where necessary. Therefore, policymakers, utilities and stakeholders will need to carefully consider what regulatory framework is going to replace COS regulation before fully transitioning away from that tried and true methodology.

In service to this concept, a number of states that have pursued PBR started off by exploring alternative regulatory approaches through robust studies and stakeholder processes. In some cases, legislatures directed state PUCs to issue reports to relevant legislative committees with findings on how PBR could be applied in their states—often with case studies exploring how PBR has played out in other states. In other cases, the state PUC or another state agency has issued findings independent of the legislature's directive, thereby sparking discourse among relevant policymakers and stakeholders.

In 2019, the Colorado legislature enacted SB 236, directing the state PUC to investigate whether PBR, with an emphasis on performance metrics and financial incentives, would be “net beneficial” to the state and align utility operations and investments with five policy goals: safety, reliability, cost-efficiency, emissions reductions and DERs growth. The following year, the state PUC issued a report to the legislature, outlining its findings and recommendations. The commission recommended starting by incorporating PIMs into existing proceedings aimed at emissions reductions through clean energy and transportation electrification planning. However, the law did not authorize the PUC to move forward with any of its recommendations without legislative approval.

In Connecticut, Hawaii and Washington, legislatures took a more affirmative stance—essentially stating their preference to pursue PBR and directing their state PUCs to figure out the best path to get there. Connecticut HB 7006 (enacted, 2020) required the state PUC to initiate proceedings to investigate, develop and adopt a framework for implementing PBR for each electric utility in the state, thereby requiring the commission to make findings on the record of certain regulatory policies. In enabling the PUC to open a proceeding, lawmakers also gave the commission authority to move forward with PBR on its own initiative; in some other states, PUCs can only respond to what a utility brings before them.

Similarly, Washington SB 5295 (enacted, 2021) required the state PUC to open a proceeding to develop a policy statement addressing alternatives to COS regulation, including several PBR approaches. The legislature required the PUC to engage in a broad stakeholder process in the proceeding to ensure robust engagement.

Hawaii became the first state in the nation to require a PBR framework for its regulated utilities that directly ties utility revenue to the utility’s performance in certain areas when it enacted SB 2939, the Hawaii Ratepayer Protection Act, in 2018. The legislation required the state PUC to engage in a robust stakeholder process to establish the PBR framework. However, the legislature also noted that its decision to move forward with PBR was initiated by a white paper developed by the state PUC four years earlier, which explored ways to better align the utility business model with customer interests and policy priorities.

Similarly, a group of stakeholders in North Carolina initiated public discourse around PBR through a yearlong process that resulted in a 2020 report, which outlined a variety of recommendations for the state’s policymakers. The stakeholder initiative, called the North Carolina Energy Regulatory Process (NERP), included a diverse group of around 40 organizations—including state officials, utilities, environmental groups, consumer advocates and more—worked to address how the state and industry would achieve the state’s goal of reducing greenhouse gas emissions from the power sector by 70% by 2030. One of the areas of focus centered around PBR, with NERP including regulatory guidance for the state PUC and draft legislation for lawmakers to consider. In 2021, the legislature adopted some of NERP’s recommendations when it enacted HB 951, which authorized PBR in the state.

DEFINING GOALS

State legislation plays an important role in defining the goals and expected outcomes from transitioning to PBR, as well. By clearly defining the expected benefits to the state and to customers, and by emphasizing the areas that lawmakers want to enhance utility performance, the legislature provides the state PUC and utility companies with guidance on how to craft the new regulatory framework.

Nearly all state legislation related to PBR outlines priority objectives or areas of focus. Some priorities are nearly universal: improved system reliability, addressing the affordability and volatility of electric rates, improving customer satisfaction, and maintaining customer and worker safety are all commonly referenced in state legislation. In recent years, several states have included additional priorities, such as reducing emissions, supporting the expansion of DERs, enhancing system resilience, enabling access to utility and customer data, and addressing issues related to energy equity.

In 2009, the Massachusetts legislature authorized the state PUC to develop rules and regulations to establish and require PBR for the state’s electric distribution, electric transmission and natural gas utilities. At the time, the PUC was required to prioritize service quality standards for the following: customer satisfaction, service outages, distribution facility upgrades, repairs and maintenance, billing service and public safety. However, the PUC wasn’t limited to those priorities. A decade after the enabling legislation, the PUC authorized a

new PBR plan for National Grid, an investor-owned distribution utility, with priorities that include reducing emissions, improving resilience and accelerating investment in clean energy technologies, such as electric vehicle infrastructure and energy storage demonstrations.

In addition to affordability, rate stability and reliability, Washington's legislation required the state PUC to consider lowest reasonable cost planning, clean energy and renewable procurement and integration, emissions reductions, demand-side management, fair compensation for utility employees, and reducing energy burdens on low-income residential customers. The Illinois legislature included many similar objectives, but also included workforce diversification and energy and environmental justice issues.

Meanwhile, the Hawaii legislature took it a step further by providing a lengthy justification for why it felt a transition away from COS regulation would be beneficial to residents, with a particular emphasis on cost containment and reducing capital expenditures.

"The existing regulatory compact rewards utilities for increasing capital expenditures by basing allowed revenues on the value of the rate base, irrespective of utility performance," the legislation states. "The legislature is concerned that the existing regulatory compact misaligns the interests of customers and utilities because it may result in a bias toward expending utility capital on utility-owned projects that may displace more efficient or cost-effective options, such as distributed energy resources owned by customers or projects implemented by independent third parties."

The legislature required the state PUC to consider the following: economic incentives and cost-recovery mechanisms, volatility and affordability of electric rates and bills, electric service reliability, customer engagement and satisfaction, availability of options to manage electricity costs, access to utility system data on aggregate energy use for third parties and individual use for customers, rapid integration and interconnection of renewables, and timely execution and interconnection of competitive third-party procurements.

PROVIDING REGULATORY FLEXIBILITY

Regulatory flexibility is a key consideration in legislation that aims to implement PBR. Even as legislatures defined their state's objectives in pursuing PBR, they did not restrict regulators from considering additional objectives and goals. They established a baseline but provided no ceiling, allowing regulators to consider ways to target emerging issues and priorities. In some cases, overly prescriptive legislation can limit the state

PUC's ability to consider options outside of what has been included in the law—whether by requiring a PBR approach that isn't right for the state or by restricting regulators from considering additional approaches that may be beneficial.

A number of states have successfully enacted legislation directing PUCs to pursue PBR without being overly prescriptive. Connecticut, Hawaii, Illinois, Massachusetts and Washington provided regulators with significant discretion and authority when it came to PBR implementation.

Connecticut required the state PUC to establish standards and metrics for measuring utility performance across various objectives, but allowed the PUC to identify the manner in which those standards and metrics would be applied to a new regulatory framework. Similarly, the legislature did not specify the mechanisms that needed to be used in a new framework; rather they simply directed the PUC to identify mechanisms that would align utility performance with desired outcomes. The PUC was required to consider the effectiveness of utility revenue decoupling mechanisms and PIMs with rewards or penalties tied to performance, but the legislation did not require that either of these mechanisms be included in the final framework.

Massachusetts was even less prescriptive; the legislation requires the state PUC to implement PBR for the state's utilities and its only specific requirement is that utilities must report annually on how their performance in certain areas compares to relevant state and national standards. However, the PBR plan for National Grid that was approved in 2019 includes a five-year MYRP, tracking of performance metrics and an earnings-sharing mechanism.

In Hawaii, the legislature similarly left the details up to the state PUC. The legislation leaned into the idea of PIMs, requiring the PUC to establish performance incentives and penalty mechanisms that directly tie utility revenue to the utility's achievements on those metrics and breaks the direct link between allowed revenues and investment levels. In response, the PUC engaged in more than two years of stakeholder work which resulted in a five-year MYRP that sets tight limits on annual rate increases and largely divorces utility revenue from capital investments, in addition to including an earnings sharing mechanism. At the same time, the MYRP includes a suite of PIMs, marketing flexibility to support new projects and services, and added financial incentives for the utility to exceed the state's renewable requirements.

In addition to developing framework details, legislation may restrict the PUC's authority to require utilities to submit PBR plans or may prevent the PUC from modifying a utility's proposed PBR plan after submission. In many cases, states have provided PUCs with the necessary authority to open PBR proceedings and, when presented with a utility's PBR proposal, to approve, deny or modify that proposal. In other cases, states have left it largely to the utility's discretion.

For example, in North Carolina, the PUC is only able to react to a utility's petition to pursue PBR. There is no requirement that utilities file performance-based ratemaking proposals. If a utility does file a PBR proposal, the PUC is not authorized to modify those plans—only to approve or deny them. By contrast, Washington now requires utilities to submit MYRP proposals in every general rate case filing, and the PUC is authorized to approve, reject or modify those proposals as it sees appropriate. This component may be critical to safeguarding consumer interests and ensuring that proposals live up to the goals established by the legislature.

ADDRESSING SHORTFALLS

In some cases, the legislature may feel that implementation has fallen short of expectations. This was the case in Illinois, which was an early adopter of legislation to enable PBR. However, the legislature felt this legislation had failed to achieve its goals. In 2021, the Illinois legislature enacted the Climate and Equitable Jobs Act—an enormous energy package that tackled everything from clean energy to workforce transition and energy justice. While regulatory reforms received less media attention, the changes enacted by the legislation are likely to prove substantial.

"Though Illinois has taken some measures to move utilities to performance-based ratemaking through the establishment of performance incentives and a performance-based formula rate … these measures have not been sufficiently transformative in urgently moving electric utilities toward the State's ambitious energy policy goals," states the legislation.

The new law requires the state PUC to establish a PBR framework designed to achieve certain objectives. It also requires electric utilities that serve over 500,000 customers to file MYRPs that tie rewards and penalties to the utility's achievement of performance metrics related to reliability and resilience, peak load reductions from demand response, expanding supplier diversity, affordability, interconnection speed and customer performance.

In particular, the legislation aimed to eliminate the use of formula rates, which the legislature determined had "resulted in excess utility spending and guaranteed profits without meaningful improvements in customer experience, rate affordability or equity." The legislation directs utilities that are currently operating under formula rates to file MYRPs and grants the PUC authority to approve or modify those plans.

Conclusion

New technologies, shifting consumer behavior and government policies are combining to transform the way electric utilities do business, and policymakers in a growing number of states are considering whether to adopt new regulatory practices to enable this new operational environment. Performance-based regulatory approaches have emerged as viable alternatives to the traditional regulatory framework. There are a variety of PBR approaches—each with its own advantages and challenges. However, with thoughtful consideration, PBR frameworks can be designed to strengthen cost containment and provide utilities with clear incentives that align their priorities with customer demands and state policy goals.

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