December 11, 2025

AR 676 RULEMAKING GENERAL RATE REVISIONS HB 3179

In the Matter of Rulemaking to Establish Multi-Year Rate Plan Framework (HB 3179 & SB 688 Implementation).

The attached report, prepared by Current Energy Group (CEG), has been developed to support the Commission's development of a Multi-Year Rate Plan (MYP/MRP) and Performance-Based Regulation (PBR) framework, in order to comply with HB 3179 and SB 688.

The report outlines a range of multi-year rate plan options, currently available and is intended to provide a comprehensive foundation of MYP frameworks. The report describes an array of approaches, their typical components, and common considerations observed across various jurisdictions.

The report is not intended to present Oregon-specific regulatory recommendations or assess Oregon-specific circumstances. Those issues-including alignment with Oregon statutes, PUC precedents, local policy and utility operating conditions-will be examined during the framework process. Future workshops will provide a more detailed evaluation of how MYP mechanisms may interreact with Oregon's unique regulatory environment.

The report includes:

- An overview of common MYP structures;
- Benefits, challenges and design considerations commonly identified in other jurisdictions;
- Discussion of how MYPs can support long-term planning, cost management, and regulatory efficiency.

The report will serve as a useful starting point for the Oregon-specific framework and policy development.

Staff Contact

If you have questions or comments, please contact Luz Mondragon at 503-510-4687 or luz.mondragon@puc.oregon.gov.

/s/ Luz Mondragon
Senior Finance Analyst
Oregon Public Utility Commission

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CURRENT
ENERGY GROUP

Multi-Year Rate Plans

Purpose and Design Considerations

Prepared for the Oregon Public Utility Commission

Authors
Dan Cross-Call
Jocelyn Durkay
Matt McDonnell
Christina Thayer

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Introduction

This report is prepared by Current Energy Group for the Oregon Public Utility Commission (OPUC or the Commission) in its consideration of multi-year rate plan (MRP) design options. This report is responsive to directives by the Commission to explore the benefits and challenges of MRPs and to directives from the Oregon State Legislature to implement MRPs and address affordability concerns. This report serves as a launching point for designing MRPs in Oregon and considering opportunities to incorporate additional performance-based regulation (PBR) components for regulated electric and gas utilities in Oregon.[1]

OPUC Order No. 24-359, concerning a general rate request by Northwest Natural Gas Company, demonstrates recent interest by the Commission in MRPs, where the Commission recognized "the administrative burden and cost that the current pace of general rate cases places on intervenors, the company, and ratepayers."[2] When these circumstances combine with an inflationary environment, state policies to reduce emissions, and other cost recovery trackers or mechanisms, the Commission concluded that "[i]t has proven difficult to test prudence, discipline costs, and ensure that areas of cost savings are incorporated into the revenue requirement."[3] The Commission expressed interest in exploring whether MRPs could reduce administrative burden, ensure just and reasonable rates and consumer protections, and provide regulatory innovation while developing utility-specific performance metrics outside the bounds of a contested proceeding.[4] To continue this exploration, the Commission directed OPUC Staff to submit and present a report at a public meeting in 2025 that addresses numerous opportunities and challenges related to MRPs, including design, timelines, and examples from other jurisdictions. The Commission also directed that Staff convene at least one workshop on these topics with stakeholders.[5] This report fulfills the referenced directive for the 2025 MRP report.

The Commission adopted similar language in Order No. 24-454, including a reiteration of the directive for its Staff to submit and present a report on MRPs.[6]

[1] This report was prepared to provide an inventory and shared reference for Oregon stakeholders of common MRP design elements, and to provide examples from MRPs adopted in peer jurisdictions that can be referenced in future Oregon deliberations. Inclusion of specific MRP elements in this report, or discussion of a feature's merits and limitations, does not necessarily indicate its fit with Oregon regulatory structures. Future deliberations by the Oregon PUC, PUC Staff, and intervenors to AR 676 and related regulatory proceedings are needed to evaluate MRP options as they relate to Oregon statutory requirements and regulatory practices.

[2] Public Utility Commission of Oregon (OPUC), "In the Matter of Northwest Natural Gas Company, dba NW Natural, Request for a General Rate Revision: Order," Order No. 24-359 (October 25, 2024), 49 at (V)(J)(3), https://apps.puc.state.or.us/orders/2024ords/24-359.pdf.

[3] OPUC, "In the Matter of Northwest Natural Gas Company...," 49.

[4] OPUC, "In the Matter of Northwest Natural Gas Company...," 49-50.

[5] OPUC, "In the Matter of Northwest Natural Gas Company...," 50.

[6] OPUC, "In the Matter of Portland General Electric Company Request for a General Rate Revision: Order," Order No. 24-454 (December 20, 2024), 121–122 at (VI)(62)(b), https://apps.puc.state.or.us/orders/2024ords/24-454.pdf.

Subsequently, in the 2025 legislative session, the Oregon State Legislature enacted HB 3179.[7] The FAIR Energy Act (Fairness & Affordability in Residential Energy Regulation, HB 3179) adopted numerous rate-related provisions, which the OPUC Staff is implementing through four open investigations.[8] Section 7(2)(a) of HB 3179 requires the Commission to adopt rules establishing MRPs for jurisdictional electric and gas utilities. Such rules would include a utility's return on equity, determine procedural and content requirements for MRPs, set MRP plan durations between three and seven years, and limit the number of utilities that can request rate increases each year.[9] Legislation also permits the Commission to establish incentives, authorize customer refunds, or provide exceptions at its discretion.[10] OPUC has opened Docket No. AR 676, consistent with legislative direction, and an October Staff Implementation Letter details proposed actions related to implementation.[11]

This report adopts the acronym **MRP** to refer to **multi-year rate plans**, consistent with the practice in some peer jurisdictions and many reports on the topic. The authors recognize that multi-year rate plans have been referred to by various other terms, including MYRP in some states, and the Oregon practice of using MYP. There is no definitive standard for which name is best; however, MRP has emerged as the commonly used acronym, and this report adopts MRP to support greater consistency across U.S. states.

The Energy Affordability Imperative

As the FAIR Act makes clear, affordability is one of, if not the primary, concern to most utility customers. This is the case in Oregon and is true across the United States.[12] Inflationary pressures combined with the need for large utility system investment have created an affordability challenge that requires both near-term relief and long-term sustainable solutions. Several jurisdictions have experience implementing MRPs, as presented throughout the paper; these provide useful models

[7] Oregon State Legislature (OSL), "Relating to public utilities; and declaring an emergency," H.B. 3179 (2025), https://olis.oregonlegislature.gov/liz/2025R1/Measures/Overview/HB3179.

[8] These investigations are Docket Nos. AR 676, AR 677, AR 678, UM 2405, which can be found on the Public Utility Commission of Oregon's webpage, https://www.oregon.gov/puc/edockets/pages/default.aspx.

[9] OSL, "Relating to public utilities...," Section 2.

[10] OSL, "Relating to public utilities...," Section 2(c).

[11] OPUC, "OPUC Staff Letter – Implementation of House Bill 3179 and Senate Bill 688," Docket No. AR 676, (October 21, 2025), https://edocs.puc.state.or.us/efdocs/HAH/ar676hah341396028.pdf.

[12] Oregon Office of the Governor, "Governor Kotek Signs Bills to Lower Energy Costs for Oregonians," Press release, August 25, 2025, https://apps.oregon.gov/oregon-newsroom/OR/GOV/Posts/Post/governor-kotek-signs-bills-to-lower-energy-costs-for-oregonians.; U.S. Senate Joint Economic Committee - Minority, "New Data: Annual Electricity Bills Are up $100 per Family Under President Trump," Press release, November 6, 2025, https://www.jec.senate.gov/public/index.cfm/democrats/2025/11/new-data-annual-electricity-bills-are-up-100-per-family-under-president-trump.

and lessons to draw upon, while it is important to recognize that those peers are navigating an energy sector in transition similar to Oregon's.

Given these circumstances, this report highlights affordability considerations across many sections and recognizes that MRP designs are evolving alongside these changing dynamics. MRPs can be an effective tool to support affordability by promoting cost containment and operational efficiencies for utilities over time. These outcomes require a long-term commitment from the regulator to establish a consistent regulatory approach and from utilities to actively pursue affordability. Finally, tools beyond MRPs are needed to address energy affordability concerns, and regulators can employ MRPs alongside rate design, other public policy or financing solutions, and strategies to address customers' total energy bills.

FAIR Act Section 7(2)(a):

(1) As used in this section, "electric or natural gas company" means any entity that is a public utility that is engaged in the business of distributing electricity or natural gas to retail customers in this state.

(2)(a) The Public Utility Commission shall establish rules requiring an electric or natural gas company to establish a multi-year rate plan for rate revisions that subject an electric or natural gas company's return on equity to review or modification.

(b) The rules must:

(A) Include procedural and content requirements for a multi-year rate plan.

(B) Require an electric or natural gas company to file a multi-year rate plan on a regular interval that is no less than three and no more than seven years long.

(C) Establish a limit on the number of electric or natural gas companies that are allowed to request a rate increase in any given year.

(c) The rules may:

(A) Provide for incentives for efficient utility operations.

(B) Authorize refunds to customers under certain circumstances.

(C) Allow an electric or natural gas company, or third party, to request an exception to a requirement established by rule under this section on a showing of good cause.

(3) The provisions of this section do not allow for cost recovery that is not permitted under ORS 757.355.

Multi-Year Rate Plan Purpose and Basics

Mult-year rate plans (MRPs) come in many forms, but the term essentially refers to a revenue requirement set for more than one year (commonly three to five years), during which adjustments to utility base rates are permitted based on variables such as an inflation index or anticipated cost increases. This stands in contrast to standard cost of service regulation (COSR), under which utility revenue and rates are set in a general rate case, and remain fixed until the subsequent rate case filing and approval. However, ratemaking is not so simple in practice. While COSR fixes base rates between rate cases, cost trackers and other reconciliation mechanisms often permit significant rate adjustments between rate cases. In contrast, MRPs can anticipate and incorporate features to account for inherent uncertainty, while placing greater responsibility on the utility to manage its operations and investments in a manner to optimize across the business enterprise.

The Case for MRPs

If well-designed, MRPs are a regulatory structure that creates cost-containment incentives for utility investment and operational efficiency. They do so by establishing a target revenue, which provides the utility with revenue certainty for a rate period of multiple years. This allows the utility to seek business efficiencies to reduce costs during the extended multi-year period and, as a result, earn higher returns by increasing the difference (margin) between revenues and costs. Analysis of MRPs in Alberta and Ontario has demonstrated this value: customers of electric distribution utilities regulated according to index-based price cap MRPs in those provinces have experienced slower rate increases as compared to COSR—of an estimated 39.3 cents for every one dollar that rates would have otherwise increased under traditional regulation.[13]

Building upon the primary rationale for MRPs of cost containment, additional benefits from well-structured MRPs include:

- **Rate reductions or bill savings, as a portion of utility cost savings, are passed on to customers** (either during the MRP period through sharing mechanisms, or over time as revenue requirements are reduced in future MRP periods resulting from realized cost containment);
- **A regulatory structure, or framework, upon which additional performance-based mechanisms can be built**, such as performance-incentive mechanisms (PIMs), to support priority outcomes and performance areas;
- **Increased margins (i.e., profit) for utilities**, if the utility achieves cost savings, cost efficiencies, or, in some cases, other outcomes with associated performance incentives;
- **Reduced capital expenditure bias**, as utilities' earnings opportunity can shift from one based exclusively on capitalized investments to solutions that reduce total costs below allowed revenue amounts;
- **Utility innovation, as well as flexibility in its management, investment decisions, or programs**, as the utility has an incentive and greater latitude to use alternative strategies and foster partnerships with third-party service providers; and

[13] Nick Crowley and Mark Meitzen, "Measuring the price impact of price-cap regulation among Canadian electricity distribution utilities." Utilities Policy 72 (Christensen Associates, October 2021): 1, 6, 7, 8. https://doi.org/10.1016/j.jup.2021.101275.

- **Reduced administrative burdens**, as the multi-year stay-out period can allow the utility (as well as regulators and intervenors) to spend less time and resources on frequent rate cases, instead giving more attention to service delivery (or monitoring and oversight).

These and other potential benefits of MRPs are available, both in theory and in practice, subject to a jurisdiction's legal parameters and regulatory practices; however, they require thoughtful design to create an integrated and balanced regulatory framework around the MRP. That requires system-oriented design thinking by the regulator and intervenors, as well as tolerance for the possibility that utilities can receive higher margins if they successfully reduce costs and achieve other performance objectives. Accordingly, MRPs require some or all of the following to be successful:

- **A multi-year "stay-out" period without a general rate case**, to provide the utility a degree of revenue certainty during which time it can focus on business management, cost control, and service quality improvements.
- **Reducing the direct link between utility revenue and costs.** Combined with a revenue or price cap, this can serve to "put the utility on a budget," which exerts cost discipline on management decisions.
- **Coordination and appropriate sequencing between utility planning and investment proposals** (e.g., integrated resource plans, distribution system plans, etc.), so those can inform rate case decisions and determination of appropriate revenues (i.e., how to set the budget).
- **Measurement and tracking of utility performance metrics** to provide transparency and accountability on outcomes, as well as to monitor performance of the MRP itself.
- **Economic analysis** to inform revenue requirements and adjustment factors, evaluate performance, and aid in the judgment of whether results are fair and earnings are justified.
- **Tolerance for utility earnings to increase if they achieve cost efficiencies**—potentially above the "authorized" ROE level if cost control proves effective enough to substantially increase utility margins.
- **Adaptive regulatory strategies**, by which the regulator holds target outcomes and primary structures stable, while updating allowed revenue and some design details for future MRP periods as new information and performance details emerge.

This case for MRPs, and the associated requirements to develop a successful MRP, compels a balanced, strategically designed regulatory framework. Regulations can allow opportunities for increased utility earnings, but that may be in exchange for less certainty that the utility will necessarily receive those financial upsides. The concept of a budget, or fixed revenue structure with fewer automatic adjustments, is a necessary feature of an MRP approach that supports cost control. Furthermore, the stringency of cost containment has an inverse correlation with regulatory lag, as the design of certain elements, such as capital funding mechanisms, impacts whether regulatory lag increases or decreases.[14]

[14] Mark Newton Lowry and Tim Woolf, "Performance-Based Regulation in a High Distributed Energy Resources Future," Lisa C Schwartz, Future Electric Utility Regulation Report Series (Lawrence Berkeley National Laboratory, January 2016), 42, https://emp.lbl.gov/publications/performance-based-regulation-high.; Nicholas Crowley et al., "Performance-Based Regulation Report With Recommendations for the Maine Public Utilities Commission"

As will be discussed in the remainder of this report, numerous MRP design features can be used to provide revenue that is neither too high nor too low to maintain utility financial health, while accounting for financial uncertainties as well as balancing utility shareholders' interests with those of customers.

Peer Examples of MRPs

MRPs have been widely employed in the U.S. and international jurisdictions for electric, gas, and water utilities. Each experience with an MRP features unique circumstances and design features. This report describes notable features for a selection of recent MRP experiences (primarily from the last 10-15 years). Prominent MRPs that are referred to throughout this report include the following:

Alberta Performance-Based Regulation Plan: Since 2009, the Alberta Utilities Commission has deployed three sequential multi-year PBR frameworks to set revenues for regulated natural gas and electric distribution utilities (six distributors total).

Connecticut PBR with Revenue Cap Formula: The Connecticut Public Utilities Regulatory Authority (PURA) issued a Proposed Final Decision in July 2025, awaiting a final decision, to adopt an MRP-based PBR structure. An accompanying Proposed Final Decision was issued to establish a set of performance incentive mechanisms and additional complementary reforms.

Great Britain RIIO Price Controls: The "Revenues = Incentives + Innovation + Outputs" (RIIO) regulatory regime took effect in 2013, to replace the previous "RPI-X" regulations. RIIO applies to network operators of electric transmission, electric distribution, gas, and water systems, and is approaching its third "price control" period to start in April 2026.

Hawaii Performance-Based Regulation: The Hawaii Public Utilities Commission adopted a PBR Framework in 2020 that includes an MRP to govern rates of the Hawaiian Electric Company's three electric utility operating companies.

Maryland MRP Pilots: The Maryland Public Service Commission (PSC) established a pilot MRP framework in 2020, followed by approval of three-year MRPs for Baltimore Gas & Electric, Potomac Electric Power Company (Pepco), and Delmarva. A second MRP period was approved for BG&E in 2023, while the PSC denied a Pepco proposal for a second MRP, due in part to a lack of appropriate cost-control measures identified by some advocates.

(Christensen Associates Energy Consulting, June 27, 2025), 49-50, 63, https://www.maine.gov/mpuc/legislative/reports.; Ken Costello, "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives" (National Regulatory Research Institute, April 2014), 25 and 33, https://nrri.org/download/nrri-14-03-alternative-rate-mechanisms/.; Cara Goldenberg et al., "Fixing Multiyear Rate Plans: Building a firm foundation for utility cost control" (RMI and Synapse Energy Economics, November 2025), 21–22, https://rmi.org/insight/fixing-multiyear-rate-plans/.

Peer Examples of MRPs
Massachusetts Performance-Based Ratemaking Plans: The Massachusetts DPU has been employing MRPs for certain water, gas, and electric utilities for several decades and, more recently, incorporated performance-based regulatory elements into MRPs. Certain design elements are standardized across utilities, while some utility-specific adjustments also exist.
Washington Multiyear Rate Plans: The Washington State Legislature enacted a law requiring gas and electric companies to file an MRP as part of their rate case proceedings beginning January 1, 2022. Each approved MRP must contain a set of performance measures as approved by the UTC.
Other states and international jurisdictions provide MRP experience that informed this work, including North Carolina, Maine, Ontario, and Australia. Those are referenced where features of their experience provide useful examples to consider for one design element or another.

Types of MRP

This report primarily considers three types of MRPs:

- **Index-based cap MRPs**
- **Forecasted MRPs**
- **Formula-based rates**

Each is introduced below, then expanded upon throughout the report. The report considers index-based cap MRPs in some detail, as that approach is recognized for centering cost containment and affordability considerations while remaining flexible to other performance objectives.[15] Forecasted MRPs are also presented, as they can incentivize cost containment when designed appropriately. In addition, the simple taxonomy of this report includes formula rate plans, as these are sometimes proposed for multi-year periods. Formula rate plans are included for completeness; however, formula rates generally do not include comparable cost-containment incentives.

In practice, MRPs tend to be a hybrid of more than one type discussed here; for example, an index-based cap MRP may include forecasts for some cost components. Numerous MRP options (or design elements) are discussed later in the report, which can be applied to an index-based cap, forecasted MRP, or other structures. Design choices for integrating and calibrating an appropriate set of MRP features will ultimately determine the quality and performance of any MRP structure.

Index-Based Cap MRPs

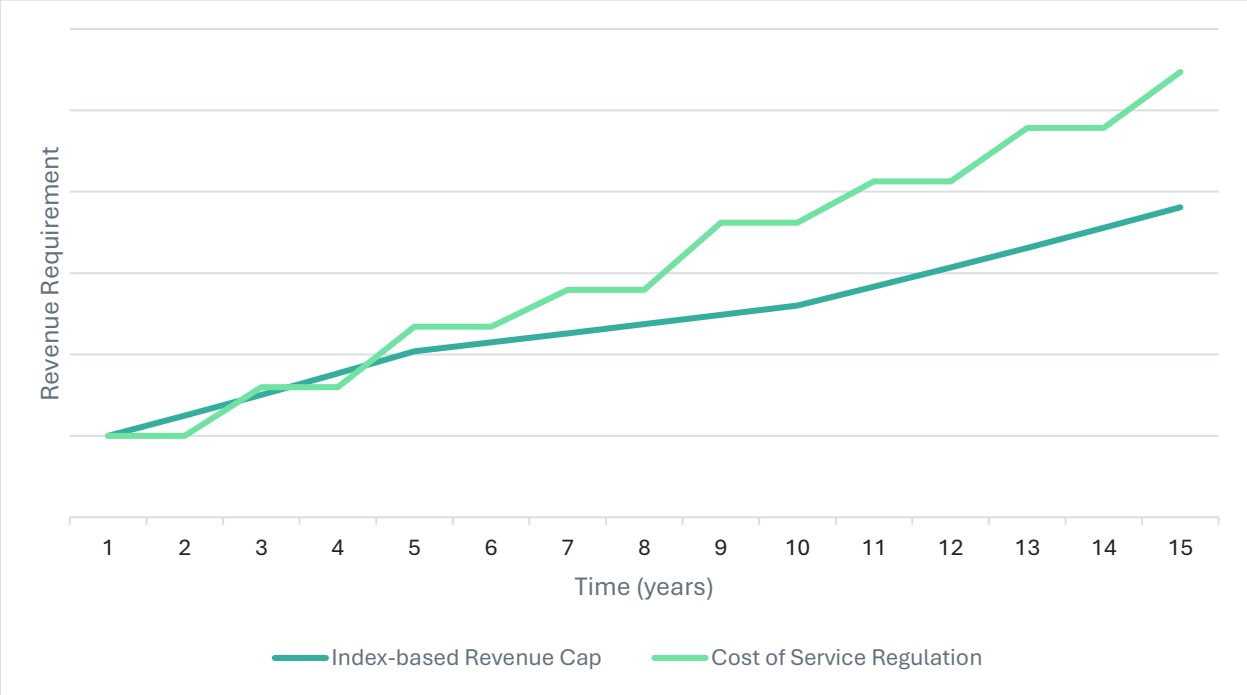
Index-based cap MRPs are a structure often associated with performance-based MRPs. In this structure, a target revenue, or cap, is set for the first year of the MRP period, then annual

[15] Lowry and Woolf, "Performance-Based Regulation in a High Distributed Energy Resources Future."; Melissa Whited and Cheryl Roberto, "Multi-Year Rate Plans - Core Elements and Case Studies: Prepared for Maryland PC51 and Case 9618," (Synapse Energy Economics, Inc., September 30, 2019), https://www.synapse-energy.com/sites/default/files/Synapse-Whitepaper-on-MRPs-and-FRPs.pdf.

adjustments are permitted based on predefined factors that are "indexed" to variables outside of utility control (such as inflation or extreme events).

Cost containment under the index-based cap approach is achieved through a series of effects that occur over the MRP period and into subsequent periods (illustrated in Figure 1). First, an appropriate revenue amount needs to be established at the start of the MRP period (the "going-in rate"), which is informed by historical or forecasted future costs and should provide sufficient revenue for the utility to make necessary investments, maintain quality service, and fulfill other obligations. Because this amount is relatively fixed (particularly with regard to base rates, which include rate base and operations and maintenance expenses), this capped revenue serves as the budget against which utility costs are managed. This budget promotes cost efficiency and grid utilization incentives for the utility, as the utility's profit motive compels it to seek cost savings and operational efficiencies during the term of the multi-year plan. The difference, or margin, between costs and revenue can be retained by the utility as profit (within reasonable limits, see discussions of *Return on Equity* and *Earnings Sharing Mechanisms*); thus, the lower the utility's costs, the higher its profit margin.

Figure 1: Illustrative Comparison of Customer Rates Under an Index-Based Revenue Cap Versus Cost of Service Regulation



At the end of the MRP period, going-in rates for the next period need to be "rebased." (This is shown after years 5 and 10 in Figure 1.) Rate setting for the next MRP period is informed by utility performance and actual costs experienced during the current period as it nears its end, thus cost containment in one MRP term should result in lower allowed revenue and rates in the next, as compared to what they would be under traditional COSR (i.e., without the strong cost efficiency incentive of the MRP). Various mechanisms and regulatory strategies can be employed to ensure that allowed revenues are just and reasonable (balanced between utility and customer interests)

and to mitigate the potential for perverse incentives to inflate costs (see, for example, discussion of efficiency carryover mechanism).

Index-based adjustments can be made either to the utility's allowed revenue or to prices (i.e., rates) paid by customers.

- **Revenue cap:** As the name suggests, a revenue cap MRP sets a target annual revenue amount for the utility, which is held fixed (subject to index-based adjustments) for the duration of the MRP stay-out period. This cap serves as the allowed revenue under which the utility will seek to lower its costs. Generally, the utility should receive the target revenue regardless of the total sales volume.
- **Price cap:** A price cap MRP sets customer rates (prices) according to rate case decisions that decide the utility's revenue requirement to recover its costs and a fair return. Annual rates are held fixed, subject to index-based adjustments. Notably, while customer rates are capped under this structure, the utility's revenues are not capped. This means the utility can increase its profits by increasing sales volume in addition to cost management strategies.

Numerous adjustment factors can be built into index-based MRPs, whether a revenue cap or price cap structure. Those should generally relate to factors exogenous to utility management decisions, to ensure that the utility has limited influence to change its revenue within the MRP stay-out period. Some of those factors are discussed below, including the discussion of an attrition relief mechanism.

Forecasted MRPs

Forecasted MRPs may also be associated with performance-based regulatory models, depending on the degree to which cost containment or other outcome-based incentives are built into the structure (see *Complementary Performance-Based Mechanisms*). The primary feature of forecasted MRPs is their reliance on forecasted costs, which are typically presented by the utility in a rate case filing. Because allowed revenue in each year of the period is derived from a utility's forecasted costs, a forecasted MRP bases its revenue determination more directly on costs that are in the utility's control. That stands in contrast to an index-based MRP, in which year-to-year changes depend on exogenous adjustment factors.

To set future years' allowed revenue in a forecasted MRP, the regulator needs to receive estimates or requests for various utility accounts and expenses, depending on which cost categories are included in the MRP-governed base rates. Those can include projected operating expenses, capital investments, depreciation, and taxes for each year in the MRP period, as well as an allowed rate of return.

Forecasted MRPs can be appealing because they directly reflect expected utility costs in the allowed revenue set for the MRP period. This provides a structure to directly compare realized (actual) costs with the forecasts used to set rates, which can be helpful for monitoring and assessing plan performance. Arguably, this is fairer than adjusting revenues or prices based on exogenous factors. On the other hand, forecasted MRPs are sometimes criticized for giving the utility too much control over estimating future costs and establishing an associated revenue requirement. Where the utility enjoys information asymmetry and could inflate its cost forecasts, there is a risk that forecasted costs and revenues are above what is needed; in that case, the utility will receive a higher profit when costs easily come in lower than forecast.

These dynamics speak to the importance of two factors that can promote cost containment and business efficiency in a forecasted MRP: 1) the need to set appropriate allowed revenues at the outset, which are not too generous or skewed by inflated cost forecasts; and 2) the usefulness of holding allowed revenue fixed after it is set at the time of the plan's adoption, to effectively serve as a cap under which the utility is motivated to reduce costs. As discussed in further detail under *Challenges and Risks*, dilution of these incentives can undercut the MRP's potential for cost containment.

Like many elements in utility regulation, there are variants on forecasted MRPs, including future test-year MRPs and step-increase MRPs.[16] Future test-year MRPs, for example, use a forecast of expected utility costs in the same manner that a future test-year rate case applies expected future costs rather than a historical test-year to set rates going forward. The difference is that annual adjustments to revenue or rates would be permitted in an MRP construct rather than holding rates fixed until the following rate case.

Formula Rates

The key characteristic of formula rates is their application of realized (actual) utility costs to determine collected revenue. Specifically, revenue is subject to adjustments and may, in fact, be automatically adjusted via embedded formula structures as actual utility costs are incurred. As a result, increases in utility costs directly lead to higher allowed revenue and rates paid by customers.

Although they often have a multi-year duration, formula rates may not induce cost control in the manner incentivized by a revenue cap. Rather than apply a revenue target or "budget" to create incentives for cost control, formula rates rely on an approved formula to automatically adjust rates based on utility costs or other financial information. Due to this lack of "performance-based" incentive, formula rates have sometimes led to confusion and controversy where they are enacted, and some practitioners have dismissed them as inappropriate to include among MRP options.

Because an index-based cap MRP also relies on a "formula," these two approaches can be confused with one another. However, there is an important difference: index-based cap plans fix a revenue (or price) that the utility can collect, with adjustments permitted based on exogenous factors, while a formula rate plan fixes adjustments to endogenous utility variables such as actual costs incurred. This means that a formula rate erodes, if not eliminates, cost-control incentives because the utility has strong assurance that it will recover any cost overruns that occur (plus earnings on additional capital costs, in some cases).

Arguably, formula rates function as a broadly scoped cost tracker, encompassing multiple cost categories and projects. Cost recovery under formula rates remains subject to prudency reviews in most cases; however, those reviews tend to be shorter and have a lower bar to approval than in a general rate case. In this manner, formula rates may be viewed as favorable to utilities and investors for their risk-reduction and assured cost-recovery properties, while potentially less supportive of cost containment and customer interests.

[16] Mark Lowry et al., "State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities" (Grid Modernization Laboratory Consortium, July 2017), 39, https://emp.lbl.gov/publications/state-performance-based-regulation.

MRP Types in Select Peer Jurisdictions		
Alberta	All electric and natural gas distributors	Index-based revenue and price caps ("I-X Index") The Commission distinguishes between caps for natural gas and electric distribution utilities – natural gas utilities are bound to a cap on revenue per customer, while electric utilities are subject to a price cap.
Connecticut	Electric distribution companies	Index-based revenue cap ("Revenue Cap Formula")
Great Britain (RIIO)	All network operators (electric transmission, distribution, gas, and water)	Custom-built model with hybrid elements of MRP structures, including reliance on network companies' proposed "business plans" for planned costs and revenue requirements (i.e., forecasted), as well as index-based adjustments for some factors.
Hawaii	Hawaiian Electric Companies	Index-based Revenue Cap ("Annual Revenue Adjustment Formula")
Maryland	Baltimore Gas & Electric and Potomac Electric	Forecasted MRP; however, with an "MRP reconciliation mechanism" that adjusts utility revenues in a manner similar in practice to Formula Rates (see discussion in *Other Revenue Adjustments*).
Massachusetts	Electric and natural gas distribution utilities	Index-based revenue cap MRP In the most recently approved electric MRP, the Department of Public Utilities (DPU) approved a revenue cap formula for operations and maintenance (O&M) expenses ("PBR-O") only.
North Carolina	Duke Energy Carolinas and Duke Energy Progress	Forecasted MRP, in which revenue increases during the MRP period are based on forecasted capital spending and are capped at 4% of the revenue requirement in year one.
Washington	Electric and natural gas investor-owned utilities	Authorized revenue changes are prescribed by the Utilities and Transportation Commission (UTC) for every year of the MRP. Adjustments to revenue are established in final MRP orders and are derived from a Commission-set rate of return on approved expenses.

Scope and Application of MRPs

MRPs can be applied narrowly and with limited scope, or integrated more comprehensively with other regulatory structures. In practice, the breadth of an MRP, including its degree of integration with other structures, exists on a spectrum. For discussion purposes, we describe two ends of that range:

- **Narrow or limited**: A narrowly scoped MRP entails limited attention or changes to other features of ratemaking (i.e., COSR practices stay primarily in place, while other regulatory

venues and processes remain mostly separate). In this case, the regulator adopts a multi-year stay-out period between rate cases, during which the utility receives a rate case decision, and the allowed revenue determinations apply for three or more years. Significant portions of utility costs and revenue may remain outside the rates affected by the MRP, for example, due to a heavy reliance on other cost recovery mechanisms, such as cost trackers or deferrals. A narrow MRP may not contain broad cost control or cost efficiency incentives and gives limited attention to other performance-based outcomes.

- **Integrated or holistic**: Alternatively, an integrated MRP structure uses the multi-year stay-out period as a structural foundation on which broader regulatory incentives get built. In this case, the MRP and additional reforms are designed using integrative, systems-based thinking to create an enterprise-wide incentive structure that aligns the utility's business strategy with regulatory and policy goals. Integrated approaches may be designed with greater intention to align incentives broadly with cost control and other regulatory or policy objectives. In addition, performance incentives for key outcomes may be incorporated in balance with earnings opportunities provided by the MRP.

It is useful to consider the degree of "integration" that an MRP framework will apply (usually early in the MRP design and implementation process) to help set the scope of issues and considerations subject to review. That can align expectations between the regulator and parties to make design choices, as well as their expected scope of impacts, more transparent and intentional.

A narrow or limited MRP has the advantage of being easier to design, as fewer additional regulatory mechanisms need to be co-developed or considered alongside the MRP. The primary consideration, in this case, is the length of the MRP stay-out period (plan duration). The multi-year duration is likely applied to the same or similar cost categories (i.e., existing base rates) as conventional rate case practice, while attention is needed to how rate adjustments will be managed during the plan period. Meanwhile, other ratemaking structures, including existing riders, deferrals, pass-through cost trackers, clean energy programs, and other regulatory features, will be managed separately according to current practice. This suggests that a narrow approach can result in some reduction of administrative burden, deriving from fewer rate cases, but the fundamental regulatory regime and its structures remain largely intact. Consequently, there may be limited broad-based influence on affordability and other objectives from a narrow MRP approach, because effects on diffuse across many other dockets and venues. In some cases, cost containment incentives could worsen if the MRP adopts flawed structures such as an excessive total revenue requirement or automatic revenue reconciliations that do not apply downward cost management pressure (see *Challenges and Risks*).

An integrated or holistic MRP can overcome some shortcomings of the narrow approach but requires significantly more design attention and strategic systems-based management by the regulator. The integrated approach recognizes that utility incentives derive from the totality of their various cost recovery structures and opportunities for utility earnings or risk management, where those exist broadly across revenue structures. It seeks to consolidate a larger portion of the utility's total revenue requirement in base rates, or, where that is not feasible, to connect cost recovery and earnings incentives through related mechanisms (such as return on equity determinations and an earnings sharing mechanism). An integrated, holistic approach also tends to incorporate additional performance-oriented structures, including PIMs and other mechanisms that reward or penalize key outcomes. It considers how to connect these incentives to the foundational MRP structures in a manner that balances the interests of the utility and its customers.

The integrated MRP approach also requires attention to how incentives and resulting outcomes, including utility financial integrity, will be maintained over successive MRP periods, thereby requiring consideration of features such as "rebasing" and capital cost recovery mechanisms. For these reasons, an integrated MRP approach requires greater time and resource commitments from the regulator, the utility, and intervenors during the initial design period and implementation of the first cycle of MRPs.

Challenges and Risks

No matter the MRP model, there are challenges and risks to design and operate (i.e., maintain) an effective MRP regulatory structure. Several notable challenges are identified here, which can reduce the cost-containment incentives of an MRP, unfairly advantage utilities at the expense of customers, or create other consequences. These are observed in some recent MRP frameworks adopted in the U.S. and are called out to provide a set of cautionary principles that should be front of mind as regulators and stakeholders design and maintain an MRP framework. In many cases, these challenges also relate to familiar shortcomings in traditional COSR regulation, such as overstated revenue requirements, where it is difficult to judge prudency due to information asymmetries between utilities and regulators.

RMI and Synapse Energy Economics identify three design flaws that can occur in MRPs:[17]

- Lack of meaningful cost-containment incentives
- Imbalanced allocation of risk between utilities and customers
- Multiple avenues for cost recovery outside of base rates

Each of these flaws can creep into an MRP in multiple ways, which means that regulators and intervenors must be diligent in recognizing the implications of every MRP design feature and weighing the pros and cons of its application. For example, the cost-containment imperative can be diluted due to excessive going-in rates at the start of an MRP period, or overuse of deferrals and cost reconciliation mechanisms that let the utility avoid the consequences of poor cost control practices. Likewise, risk may not be fairly distributed between utilities and their customers if earnings sharing mechanisms are too protective of utility downside scenarios, resulting in customers paying for a utility's inability to meet performance expectations. Finally, the importance of the MRP itself—that is, the extent to which it will capture utility management's attention and promote cost control—has a direct relationship with the proportion of utility revenue that is collected in base rates (or share of revenue that is subject to the MRP revenue allowance). If a utility's revenues are heavily composed of deferrals, riders, or adjustment clauses that operate separately from base rates, these can insulate the utility from the consequences of its business decisions and operating efficiency, making the MRP a relatively smaller feature of its overall financial outlook. Finally, if the criteria for exceptions or "off-ramps" for a utility to make an early exit from an MRP stay-out period are too easily achieved, it can reduce utilities' need to make difficult business decisions because the MRP is unlikely to be enforced.

In addition, MRPs can create additional administrative complexity and regulatory resource needs to design and manage the framework. This may be surprising or run counter to expectations for

[17] Goldenberg et al., "Fixing Multiyear Rate Plans: Building a firm foundation for utility cost control."

reduced administrative burden from MRPs. Regulators and intervenors should recognize, however, that MRPs introduce new, sometimes complex, unfamiliar, or controversial elements that need to be addressed. For example, an index-based cap MRP may require economic studies of the appropriate productivity factor (or X-factor) to use for revenue adjustments. Similarly, forecasted MRPs require network familiarity and expertise to properly judge the merits of planned investments or operating strategies, as well as a high degree of strategic decision-making to determine how much of the revenue request to approve.

Of course, some of these administrative complexities and expertise requirements are present for traditional COSR regulation as well. The resource intensity and added burden of MRPs may be most acute during design stages and implementation of the first MRP period. Through sequential applications and experience, those burdens should decrease as structures are put in place. Strategic focus can then shift to areas of refinement. Nonetheless, it is important to recognize the up-front effort and resources that could be required to shift to a new regulatory paradigm.

MRPs can also introduce new challenges that are different from traditional COSR regulations. Among those is the potential for utilities to earn higher earnings if they succeed in their cost control efforts (or if allowed revenue was set too high and margins were easy to achieve). Under this scenario, attention and criticism can result in cries of foul or seeking to claw back utility gains. Regulators will need to navigate those circumstances to investigate results while balancing the need for regulatory stability and trust in regulatory structures, for the utility, customers, and the public. In some cases, reactive course changes or claw-backs may be ill-advised, where instead refinement to improve future MRP periods can be made. Some jurisdictions outside the U.S., including Great Britain and Alberta, have demonstrated fairly durable performance-based MRP structures, characterized by continued refinements and a willingness to adapt based on experience.

MRP Design Elements

MRPs are a framework composed of different design elements (or features) and related regulatory mechanisms. Some elements are necessary for any MRP (such as choice of plan length or stay-out period), while others are optional (such as whether to design around an attrition relief mechanism with indexed adjustments). In many cases, an element is inextricably a feature of an MRP, although it may not always be expressly deliberated during MRP design. A utility's "going-in rate," for example, is a fundamental determination to set a utility's revenue requirement; these amounts may be determined in different regulatory venues, such as a general rate case; however, they are core to the MRP incentive structure, and it is important to devote some attention to at least *how* or *where* rates will be set.

The following sections provide introductory discussions of common MRP features that need attention or may be considered in MRP design. This can serve as a menu-style inventory of options, as well as a presentation of primary considerations and pros or cons for each. Additional details and historical experience can be found in *Appendix A: Suggested Reading* at the end of this report, as well as through a deeper review of MRP applications in peer jurisdictions.

Plan Duration

A multi-year period, or duration, is a definitional design feature of MRPs: the regulator establishes a utility's base rates and the type and degree of adjustments permitted; then, with limited exceptions,

rates are not reset through a rate case for multiple years. The plan duration may also be referred to as the "stay-out period," the "MRP period," or simply "plan period."

MRP periods are generally set between three- to seven-years, with some recent tendency toward four- and five-year durations. The plan duration should provide a sufficiently long period of time for the utility to have a meaningful opportunity to pursue cost efficiency and innovation in its service delivery, without the overhanging attention that a rate case creates. Multi-year stay-out periods also aim to reduce the administrative burden of frequent rate cases. For example, in the context of rate cases that can take 12 or more months from initial filing to final decision, in addition to many months in advance for the utility to prepare its proposals, there should be at least that much time without adjudicated rate case activities.

The length of the plan period is also important to balance with recognition that the utility industry is undergoing rapid changes, which impact capital investments, customer rates, and public interest objectives; and an overly-long plan period may be challenged by these changes. Some jurisdictions, such as Great Britain, have reduced eight-year plan periods to five years to better allow for updates as needed. Plan periods are intended to occur consecutively, and as a result, adjustments to MRP design elements for the next plan period typically occur during the final year of an existing plan period.

The length of the plan period is set at the outset of an MRP, and regulators may determine what circumstances could necessitate any adjustments during the period or when a utility may reset rates or exit the MRP before the conclusion of the period (see *Off-Ramps and Reopeners*). Generally, the plan duration should be set and not adjusted to preserve the cost containment and cost efficiency objectives of an MRP. As detailed below, other MRP design elements are intended to account for exogenous factors (such as the inflation factor) and endogenous factors (such as a capital adjustment factor) during the plan period. Regulators also have an opportunity to adjust revenue collection and base rate recovery from one plan period to the next through the rebasing process (discussed below).

Adhering to the plan duration is important to ensure an MRP's cost-containment elements have reasonable chances of being realized: while some design elements—such as attrition relief and capital funding mechanisms—provide more immediate incentives to utilities, customer benefits from cost efficiencies may take years to be realized. By exiting an MRP early, especially for circumstances that are not truly extraordinary in nature, the benefits of an MRP may be blunted. In Connecticut, a pending proposal for performance-based MRPs for electric distribution companies recognizes this dynamic by stating, "Intervening rate amendments are contrary to the intent of an MRP and may disrupt the delicate balance of the benefits achieved through the MRP."[18]

[18] Connecticut Public Utilities Regulatory Authority (CT PURA), "PURA Investigation into Revenue Adjustment Mechanisms for a Performance-Based Regulation Framework: Proposed Final Decision," Docket No. 21-05-15RE01 (July 14, 2025), 10, https://www.dpuc.state.ct.us/DOCKCURR.NSF/8e6fc37a54110e3e852576190052b64d/1555634f73ae53a685258cc7007a62fb?OpenDocument.

Plan Duration in Select Peer Jurisdictions		
Alberta	5 years	Each index-based MRP established by the Commission spans five years. The latest MRP covers service from 2024 through 2028.
Connecticut	4 years	PURA's proposed decision would require applicable electric utilities to submit a written acceptance of the four-year plan period within 10 days of issuance of the final decision.
Great Britain (RIIO)	5 years	Five years in Price Control periods 2 and 3 RIIO previously used an 8-year duration in Price Control 1 (2013-2021 for transmission and gas companies; 2015-2023 for electric distribution companies), which was found to be too long to allow updates when needed.
Hawaii	5 years	In the decision adopting the PBR framework, the Commission stated that a five-year MRP term should be sufficient time to start transitioning the state's traditional ratemaking process and realize benefits from the plan.
Maryland	3 years	Used during the MRP "pilot" period for select utilities in Maryland, including MRP-1 (2021-2023) and MRP-2 (2024-2026) for BG&E, and MRP-1 (2022-2024) for Pepco, before the Commission order to deny the next Pepco MRP.
Massachusetts	5 years	Electric and gas distribution utilities operate under index-based MRPs that span five years. The Department has approved 10-year plan periods in some instances previously.[19]
North Carolina	3 years	Three-year MRPs were first adopted in 2023 by NCUC for Duke Energy Progress and Duke Energy Carolinas, for 2024-2026. The utilities have requested a two-year rate period for 2027-2028, subject to rate case review in 2026.
Washington	2 – 4 years	Enabling legislation prescribes a minimum of two years for an MRP, with a maximum of four years. Utilities are permitted to submit proposals for a new MRP beginning in Year 3 or Year 4 of an MRP period.

[19] Massachusetts Department of Public Utilities, "Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service, a Performance-Based Ratemaking Plan, and a Capital Recovery Mechanism: Final Order," Docket No. 23-150, (September 30, 2024), 80-81, 98-99, https://www.mass.gov/info-details/dpu-23-150-national-grid-electric-base-distribution-rate-case#links-and-more-

Going-In Rates

Going-in rates are the amount of allowed or target revenue that is set for the utility in Year 1 ("base year") of an MRP period. This Year 1 revenue amount also serves as the starting point from which adjustments get made—whether those are reconciliations in that year or planned adjustments in future years of the MRP period. Because cost-containment incentives are heavily determined by the total revenue that the utility is allowed to collect during the MRP period, the going-in rate is very consequential. If the going-in rate is set too low, then the utility will not have sufficient revenue to invest in and operate the system; if the rate is too high, then the utility can too easily reduce costs below its revenue, and no additional cost efficiency will be achieved. In this way, going-in rates serve as the foundation on which the scaffold of the MRP rests.

The rate-setting process for going-in rates under an MRP resembles the ratemaking process under COSR in some respects, often involving a revenue requirement set for a plan period using a selected test year and a cost of service study; determining approaches to plant-in-service, depreciation, and operations and maintenance expenses (O&M); and establishing how and when prudence reviews occur. However, MRPs also include design elements that may be less common in COSR: management audits; how various caps, indices, and adjustment factors are developed and applied to going-in rates; and efficiency carryover mechanisms. While MRPs may relieve administrative burdens over the duration of the plan, designing going-in rates remains a crucial component of the rate-setting process that requires significant attention, especially as underlying decisions will remain in place for three to seven years, depending on the length of the MRP period.

Given the recent rise in utility rates nationally,[20] mounting requests for increased capital investments, and the potential for actual costs to fluctuate between years, the choice of test year for going-in rates can have a substantial impact on a utility's revenue over the MRP term. A recent report by RMI on common flaws in MRP design cautioned that setting the allowed revenue too high can result in customers paying higher amounts than what is reasonable, where "any resulting 'savings' create the illusion of cost-efficiency gains."[21]

The respective benefits and risks of historical, current, and future test years in rate setting also remain a relevant consideration in MRPs. For example, historical test years provide financial information from actual investments but may require modifications or could increase the need for rebasing if anticipated costs differ substantially from historical costs. Alternatively, future (or fully-forecasted or forward) test years can better account for expected types and levels of investment but may exacerbate information asymmetry and generate more controversy due to their reliance on a utility's forecasts. Ultimately, the costs and expenditures over the plan period that are recovered through going-in rates and other adjustments should reflect anticipated expenses over the upcoming plan period, as well as a fair and risk-adjusted return for the utility.

information. In addition, note that the Departments approved a five-year plan period with the possibility for a five-year extension in the Final Order issued for Docket No. 22-22, pages 55-56. The Department also approved a 10-year plan period in DPU 19-120, pages 65-66. These Final Order can be found at the DPU's Docket Search webpage: https://eeaonline.eea.state.ma.us/dpu/fileroom/#/dockets.

[20] Ryan Wiser et al., "Recent Retail Electricity Price Trends: What Do We Know... or Think We Know?," Online, Slide show, (Lawrence Berkeley National Laboratory, October 2025), 13-19, 32, 34, https://eta-publications.lbl.gov/sites/default/files/2025-10/presentation_retail_price_trends_drivers.pdf.

[21] Goldenberg et al., "Fixing Multiyear Rate Plans: Building a firm foundation for utility cost control," 14.

Management audits are not unique to jurisdictions with MRPs, and can be beneficial in an MRP-based structure to identify areas for cost savings or greater efficiencies, provide a baseline for measuring performance improvements, and inform the development of a productivity factor. This can also help ensure that going-in rates are set at a reasonable level.[22] One example of this is a management audit in Hawaii that identified a $25 million opportunity for annual capital and operations and maintenance savings, which was subsequently factored into the revenues of the first MRP.[23]

Practice in Select Peer Jurisdictions		
Alberta	Forecasted test years	The Commission adopted the latest approved rates for the 2024-2028 plan period, set using a COSR methodology and a forecasted test year spanning two years. In addition, the Commission rejected applications by utilities to adjust the approved rates to reflect actual costs incurred prior to the MRP period.
Connecticut	The most recent 12-month period available, ending at a calendar quarter	Consistent with state regulation, historical test year with known and measurable adjustments for O&M expenses COSR using a historical and future (Year 3) test year[24]
Great Britain (RIIO)	Business plans proposed by network operators	Network companies submit a business plan that includes the requested revenue. Regulator reviews plans and determines the amount to be approved.[25] A business plan incentive provides awards and penalties to encourage "truth-telling" in the company plans through stages of review.[26]
Hawaii	Historical test year from rate case	Going-in rates for the initial MRP period were adopted based on settlement agreements reached in each company's last rate case. Historical test years were used in rate cases to derive allowed revenues.

[22] Goldenberg et al., "Fixing Multiyear Rate Plans: Building a firm foundation for utility cost control," 6.
[23] Ray Tulloch and Wayne Martell, "Management Audit of the Hawaiian Electric Company (HECO) Final Report: Prepared for the Hawaii Public Utilities Commission," (Munro Tulloch, May 12, 2020), 12, https://hpuc.my.site.com/cdms/s/puc-case/a2G8z0000007fF1EAI/pc21184.
[24] CT PURA, "PURA Investigation into Revenue Adjustment Mechanisms...," 14-16.
[25] In Ofgem's 2025 draft decision, the regulator proposed to disallow 26% of all network companies' estimated total costs (total expenditure, composed of capital and operating costs), covering electricity transmission, distribution, and gas companies.; Great Britain. Office of Gas and Electricity Markets, "RIIO-3 Draft Determinations Overview Document," Consultation, (July 1, 2025), https://www.ofgem.gov.uk/consultation/riio-3-draft-determinations-electricity-transmission-gas-distribution-and-gas-transmission-sectors.
[26] Elizaveta Kovaleva, "Ofgem RIIO-3 Draft Determinations," Oxera, July 4, 2025, https://www.oxera.com/insights/agenda/articles/ofgem-riio-3-draft-determinations/.

Massachusetts	Historical test years with adjustments	Going-in rates are established using historical test years, adjusted for known and measurable changes. Test years are typically a 12-month calendar year, although the Department has approved split test years when sufficient justification has been provided.[27]
Washington	Historical test years with adjustments	MRP going-in rates are set using historical test years, with limited adjustments approved by the Commission.

Return on Equity

Regulators are responsible for setting and approving a utility's return on equity (ROE), which is the rate that a utility's shareholders expect to earn on the equity portion of capital expenses and comprises one element of a utility's total authorized rate of return. A utility's ROE should permit it to effectively attract capital, while its level should be set commensurate with risk and encourage management efficiency.[28] ROE is directly borne by customers as a component of utility revenue, which is translated into going-in rates. Analysis from RMI identified that ROE accounts for 15-20% of customer bills.[29]

If ROEs are too high, then other misaligned incentives can be exacerbated. For example, capital bias arises from the ability to earn on capital expenditures directly; the higher the available ROE is above the cost of equity, the stronger the bias to invest in capital projects becomes.[30] One analysis identified that a one percentage point rise in ROE increases capital assets by 3-4%.[31] Another result of this dynamic is that the utility's interest in seeking alternatives and in pursuing cost containment broadly is reduced.

Utilities' authorized ROE is at the heart of their incentives under any regulatory structure, including MRPs. The process that a regulator uses to determine an appropriate ROE—or the authorized ROE—may not differ under an MRP as compared to COSR. As risk factors and opportunity for

[27] Massachusetts Department of Public Utilities, "Petition of Massachusetts Electric Company and Nantucket Electric Company...," 12-18, 30-36.; Massachusetts Department of Public Utilities, "Petition of Boston Gas Company, doing business as National Grid, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Gas Service and a Performance-Based Ratemaking Plan: Final Order," Docket No. 20-120, (September 30, 2021,), 10-20, https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//gjaggggj?AFMhDNZxudKnPMmfFp4vOmFJ0ioKRMXdZYr4j7j/42qk9v9pxUxyG6LkaCeWBSjqbmMlNqhcSkxPf0qUr1gASPKrYE1qejvebf677PtCVStUdHoHpEGELGLGjR+ZpYgt.

[28] David Boonin, "Return on Equity - Focus on Effective Regulation," Slide show, (National Regulatory Research Institute, November 2008), 2, https://pubs.naruc.org/pub/4ADC1D5A-2354-D714-5138-F4D19F047EBA.

[29] Joe Daniel et al., "Rebalancing 'Return on Equity' to Accelerate an Affordable Clean Energy Future," (RMI, February 21, 2025), https://rmi.org/rebalancing-return-on-equity-to-accelerate-an-affordable-clean-energy-future/.

[30] "Electricity Affordability Toolkit: Return on Equity Reform," (RMI, September 21, 2025), https://affordability-toolkit.rmi.org/policies/return-on-equity-reform.; Daniel et al., "Rebalancing 'Return on Equity'...".

[31] Karl Dunkle Werner and Stephen Jarvis, "Rate of Return Regulation Revisited" (Energy Institute at Haas, March 2025), 6, https://haas.berkeley.edu/wp-content/uploads/WP329.pdf.

return shift under an MRP, from cost-containment incentives, risk-sharing mechanisms, or other features, authorized ROE may be subject to some adjustment itself. Incorporating more performance-based elements can better link ROE with public interest or policy objectives.[32] For example, MRPs can use an earnings sharing mechanism to reconcile substantial over- or under-earnings during the MRP period. A proposal under consideration by the Connecticut PURA seeks to continue to use traditional methods of establishing ROE, treating performance incentives and penalties separately from this determination, and noting it will consider performance-based mechanisms when evaluating a utility's risk factors.[33] Other jurisdictions have lowered ROEs to reflect reductions in risks that utilities faced under an MRP.[34]

Utilities may also have an opportunity to earn a higher ROE under a capped MRP structure, which may exceed its authorized levels. Such instances may indicate achieved cost efficiency and, as such, may be appropriate to permit the utility to retain this incentive. This was seen following Alberta's prior MRP period, in which the Alberta Utility Commission concluded that ROEs above authorized levels were evidence of successful cost management and an indication for continuing on the MRP path.[35]

Earnings Sharing Mechanism

Earnings Sharing Mechanisms (ESMs) are closely associated with ROE and are a structure for the utility to share a portion of over- or under-earning outside the authorized ROE. This can protect the utility from underearning and customers from paying for excess utility earnings. The protection from excess, or windfall, profits is a particularly useful feature in MRPs, in which a strong cost-containment objective, and allowance for the utility to earn above what may otherwise be an earnings ceiling, could result in significant cost-cutting and business efficiency improvements without those benefits getting shared with customers. At the same time, it may be useful to permit some additional earning potential for utilities if they succeed in cost-control measures.

In combination with appropriately set ROE and other incentive structures (e.g., performance incentives), an ESM can ensure fair earnings opportunities for the utility and balance utility interests with those of customers. An ESM can also maintain authorized ROE in a range that helps support utility financial metrics and necessary capital raises from debt and equity markets.

Regulators must consider various features of ESM design, including whether to bound the ESM at an upper band above which the utility no longer earns and all excess earning is credited back to customers. ESMs can also include a "deadband" around a target ROE, within which there is no sharing (*i.e.*, the utility retains all earnings or bears risk of underearning). A deadband can be designed to be symmetrical or asymmetrical. ESMs with asymmetrical deadbands enable excess

[32] "Electricity Affordability Toolkit: Return on Equity Reform."; Cara Goldenberg and Kaja Rebane, "How to Restructure Utility Incentives: The Four Pillars of Comprehensive Performance-Based Regulation" (RMI, July 2024), 36, https://rmi.org/insight/how-to-restructure-utility-incentives-four-pillars-of-comprehensive-performance-based-regulation/.
[33] CT PURA, "PURA Investigation into Revenue Adjustment Mechanisms...," Appendix A, xi.
[34] Goldenberg et al., "Fixing Multiyear Rate Plans: Building a firm foundation for utility cost control," 31 footnote xlii.
[35] Canada. Alberta Utilities Commission, "2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities: Decision 27388-D01-2023," Proceeding 27388, (October 4, 2023), Table 1, pages 8-9, 41-43, https://prd-api-efiling20.auc.ab.ca/Anonymous/DownloadPublicDocumentAsync/794425.

earnings to be returned to customers but do not protect the utility from underearning. Regulators may also consider whether the ESM should incorporate sharing "tiers" (*e.g.*, higher amounts returned to customers as overearning increases). Determination of these details can be made during MRP design processes, taking into account the full balance of incentives, earning opportunities, customer benefits, and other mechanisms that are incorporated in the ratemaking paradigm. As with many design elements in an MRP, a successful ESM balances both the risks and benefits of under- and over-performance fairly between a utility and its customers.[36]

Figure 2: Example Earnings Sharing Mechanism Designs

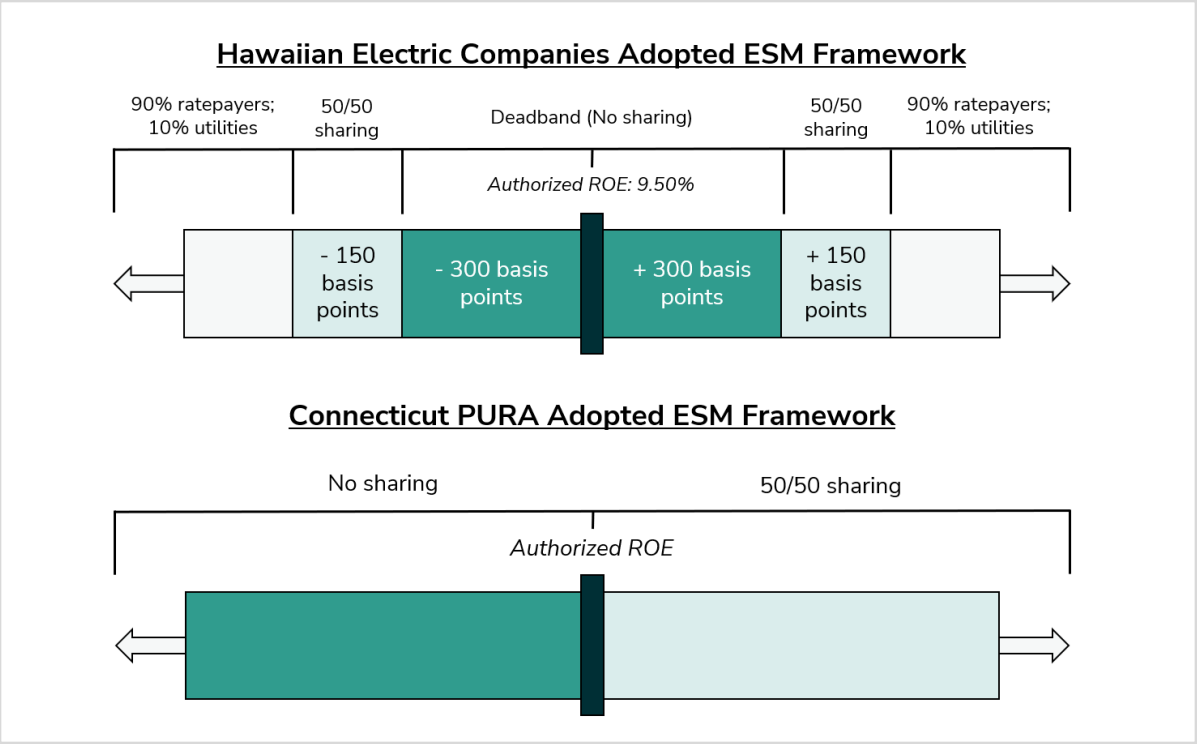


Figure 2 illustrates two examples of ESM design: for Hawaii's adopted ESM and the proposed structure in Connecticut. As seen, Hawaii's ESM is a symmetric design including a deadband on either side of the authorized ROE. In this structure, the utility is permitted to earn above the authorized ROE by up to 3 percentage points, after which a portion of those earnings is returned to ratepayers. A symmetric structure is applied to the utility downside scenario. If the utility significantly underearns below its authorized ROE, ratepayers will contribute on a graduated scale to maintain minimum utility earnings. In contrast, the Connecticut ESM would be asymmetric with no deadband. The Connecticut approach would share upside earnings with customers if the authorized ROE is exceeded, without comparable downside protection for the utilities if they do not achieve their authorized ROE. In both structures, the utility has the opportunity to retain earnings that exceed its authorized (or target) ROE; this permits upside earning potential that may be larger

[36] Goldenberg et al., "Fixing Multiyear Rate Plans: Building a firm foundation for utility cost control," 25-26.

than a traditional COSR structure, but requires strong utility performance during the MRP to achieve cost savings.

ESMs are fairly common in utility ratemaking, and generally are set based on judgment by the regulator following utility or intervenor input. They may require legislative authorization in some states, and occasionally legislation has specified specific design parameters. The following table describes some ESM structures that have been proposed or adopted in peer jurisdictions.

Practice in Select Peer Jurisdictions		
Alberta	Asymmetric, two-tiered ESM	Asymmetric, two-tiered ESM with an initial deadband set at 200 basis points above approved ROE The first tier above the deadband spans the subsequent 200 to 400 basis points, with 60% of earnings apportioned to the utility and 40% to customers. Conversely, earnings at 400 basis points and above the ROE are split, with 20% going to the utility and 80% being shared with customers.
Connecticut	Asymmetric ESM	Asymmetric ESM in which upside earnings above the allowed ROE are shared 50/50 between customers and shareholders No deadbands. No additional tiers beyond the 50% sharing structure. ESM does not apply to earnings that may be received from PIMs, so as not to dilute the incentive available from the PIMs.
Great Britain (RIIO)	Symmetric, two-tiered return adjustment mechanism	Return adjustment mechanism is employed in RIIO-2 price control and proposed to continue in RIIO-3. 50/50 sharing after a 300 basis point deadband above and below allowed ROE; 90/10 sharing beyond 400 basis points. Adjustments are made at the end of the control period (rather than annually).[37]
Hawaii	Symmetric, tiered ESM	Symmetric, tiered ESM in which the initial deadband is set at 300 basis points above and below the allowed ROE of 9.50% The next 150 basis points above and below the deadband are split evenly between the utility and customers. Performance outside of the identified deadband and supplemental band is apportioned 90% to customers and 10% to the utility.

[37] Great Britain. Office of Gas and Electricity Markets, "RIIO-3 Draft Determinations - Finance Annex," Consultation, (July 1, 2025), https://www.ofgem.gov.uk/consultation/riio-3-draft-determinations-electricity-transmission-gas-distribution-and-gas-transmission-sectors.

Practice in Select Peer Jurisdictions		
Massachusetts	Varies by utility	The Department has approved asymmetric ESMs with a deadband of at least 100 basis points for multiple utilities, but the deadband, tiers, and apportionment vary by utility.[38] One such ESM apportions under-earnings to customers.[39]
Washington	Asymmetric ESM	The enacted MRP legislation requires that any utility earnings that are greater than 0.5% higher than the authorized rate of return must be refunded to customers or returned through another method, subject to an administrative proceeding.

Attrition Relief Mechanism

The indexing of an indexed-cap MRP structure is sometimes called an attrition relief mechanism (ARM), which provides utility revenue adjustments according to factors and considerations established in advance of the MRP period. The "attrition" named in this mechanism refers to the potential erosion of earnings that could occur over time if revenues do not adjust for changing costs. "Relief" is provided in the form of adjustments that are indexed to external factors or pre-determined values that are not directly associated with the utility's actual, not yet revealed costs.

The attrition relief mechanism functions as an algebraic formula where target revenues in each year of the stay-out period can be expressed in mathematical terms, as illustrated below. In practice, some terms are more indexed, or mathematical in nature, such as the inflation or X-factor adjustments, while others, like the Z-factor, indicate the ability to adjust for unknown future events.

$$\text{Target Revenue Year}^{N} = \text{Target Revenue Year}^{(N-1)} + \text{Inflation} - \text{X-factor} + \text{K-bar} + \text{Z-factor} + \ldots$$

[38] Massachusetts Department of Public Utilities (MDPU), "Petition of Massachusetts Electric Company and Nantucket Electric Company...," 91-94, 108-112.; MDPU, "Petition of NSTAR Electric Company, doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Plan: Final Order," Docket No. 22-22, (November 30, 2022), 70, https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//giabjige?dkAx11d8UoPWenGa6m4mCsEmiDhMBXK0ednWT8WFP5Ok9v9pxUxyG6LkaCeWBSjqbmMlNqhcSkxPf0qUr1gASPKrYE1qejvebf677PtCVStUdHoHpEGELGLGjR+ZpYgt.; MDPU, "Petition of Boston Gas Company, doing business as National Grid...," 101.

[39] MDPU, "Petition of NSTAR Gas Company doing business as Eversource Energy, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Gas Service and a Performance Based Ratemaking Mechanism: Final Order," Docket No. 19-120 (October 30, 2020), 89-90, https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//fdagajgj?/bOGR0SLKR7/ih5QIpjs32FJ0ioKRMXdZYr4j7j/42qk9v9pxUxyG6LkaCeWBSjqbmMlNqhcSkxPf0qUr1gASPKrYE1qejvebf677PtCVStUdHoHpEGELGLGjR+ZpYgt

The factors that compose an attrition relief mechanism can be a combination of fixed numbers (e.g., 0.6% adjustment per year) as well as guiding principles or guardrails that govern when additional adjustments may be necessary. The above formula includes a sample of some of the more common factors applied in index-based MRPs. The following descriptions explain those and a selection of other factors that can be considered.

Inflation factor (I-factor)

An inflation factor (I-factor) is a common, relatively simple adjustment factor to include in an ARM. It ensures that utility revenue is permitted a minimum annual adjustment to keep up with inflation, recognizing the exogenous nature of price inflation, which is fully outside the utility's control. Regulators can consider a variety of external indices to peg I-factor adjustments to, including broad-based macroeconomic inflation measures or sector-based measures such as a producer price index. In practice, jurisdictions have often resolved to apply macroeconomic (i.e., broader) inflation measures, such as the Gross Domestic Purchases Price Index (GDPPI) as reported by the United States' Bureau of Economic Analysis.

Practice in Select Peer Jurisdictions		
Alberta	Weighted composite of Alberta-specific labor cost index and consumer price index	Comprised of two weighted components reflecting the indexed costs of labor and non-labor components. The cost of labor is determined by the Alberta "Fixed Weighted Index," which reflects the monthly average hourly earnings for all employees by industry. Alberta's consumer price index addresses non-labor inflationary inputs. The labor component is weighted to 60% of the I-Factor, and the non-labor component is adjusted to 40% of the I-Factor.
Connecticut	GDPPI	Adjustment applied annually beginning in Year 2, based on the most recent four quarters of GDPPI. I-factor adjustment is excluded from some variables in the Connecticut "Revenue Cap Formula," including Z-Factor, CT-Bar, PIMs, shared savings mechanisms (SSMs), and storm cost recovery.
Great Britain (RIIO)	Real price effect	Annual adjustment made by the regulator for real price effects that are derived from a composite of external inflation indices, including relevant input prices of materials applicable to each utility type.
Hawaii	GDPPI	Annual adjustment made according to the annual forecasted change in GDPPI.

Practice in Select Peer Jurisdictions		
Massachusetts	Various approaches	The Department has approved adjustments based on the GDPPI previously.[40] In a recent decision for National Grid's electric utility, the Commission set a minimum of 0.21% for the utility based on partial factor productivity (O&M) and a 5% cap using a weighted composite index of the ECI-Northeast utility labor index and the Producer Price Index for Electric Utilities.[41]

Productivity factor (X-factor)

The productivity factor (X-factor) is an economic measure of how much more efficient–or productive–a firm becomes over time, in terms of changes in output compared to a unit of input. A positive X-factor, for example, of 1.0, suggests that the firm can increase its output by 1% annually, given the same level of inputs. Combined with the I-factor, this lends itself to the "I-X" concept that is sometimes associated with MRPs and attrition relief mechanisms. In a sense, the X-factor serves to fine-tune the I-factor for industry-specific circumstances, and in combination, they attempt to mimic the competitive pressures that face the utility sector.

Determination of the numeric value to apply as an X-factor is informed by a choice of methodologies, all of which employ economic analysis.[42] Most commonly, total factor productivity (TFP) studies are used. A TFP study calculates the difference in growth rates between a company's physical outputs and physical inputs. It can be based on a review of historical trends for a set of peer businesses in a firm's sector (in this case, peer electric or gas utilities). The concept is that more productive firms will be able to produce more outputs given the same level of inputs than a less productive firm, and that over time, a productive firm should increase its productivity, resulting in a downward trend in the firm's costs (per unit of output). This is a natural result for firms operating in a competitive market environment—gained experience, combined with competitive pressures, tends to increase the firm's productivity, leading to lower costs (independent of other factors such as inflation, hence the purpose of separating these factors in an ARM formula). In the context of utility regulation via an indexed revenue formula, this X-factor adjustment seeks to mimic those competitive market forces to drive productivity gains over time.

A positive X-factor—for example, a value of 1.0—represents increased firm productivity, which through the negative (minus) sign in the ARM formula, would lead to a 1% per year reduction in the revenue cap (all things equal; i.e., in the absence of other upward adjustments that may result from the I-factor, allowance for additional capital expenditures [e.g., K-bar], or cost recovery that

[40] MDPU, "Petition of Massachusetts Electric Company and Nantucket Electric Company...," 83, 101.
[41] MDPU, "Petition of Massachusetts Electric Company and Nantucket Electric Company...," 82-83.
[42] Brittany Tarufelli and Mark Weimar, "Evaluating the X-Factor: A Brief Overview of Methodologies and Best Practices" (Pacific Northwest National Laboratory, May 2022), https://emp.lbl.gov/sites/default/files/2024-01/tfp_and_the_x_factor_journal_article_v_final_6_5_2023_0.pdf.; Yatchew et al., "Review of Total Cost Benchmarking Methodology for Electricity Distributors," (Ontario Energy Board and University of Toronto Climate Positive Energy, November 12 ,2024), https://www.oeb.ca/sites/default/files/Review%20of%20Total%20Cost%20Benchmarking%20Methodology%20for%20Electricity%20Distributors.pdf.

operates outside of MRP-impacted base rates). In recent years, some utility productivity studies have revealed negative productivity growth in the sector, suggesting a negative X-factor value. If applied in an indexed ARM (subtraction of a negative value), that would lead to utility revenue rising faster than the rate of inflation.[43] Some commissions have elected to set the X-factor at zero due to discomfort with this result, as it could be seen as permitting declining utility efficiency, and also as it serves to escalate rates.

As these circumstances indicate, determining an appropriate X-factor can be controversial. Frequently, utilities and other parties with competing interests make different arguments for what fair productivity assumptions and methods are to apply in setting this value. To inform regulatory decisions, the utility and parties may be invited to submit economic studies that analyze and make the case for proposed values, while the regulator weighs those proposals, or may choose to commission its own analysis.

Practice in Select Peer Jurisdictions		
Alberta	0.1% productivity + 0.3% premium	The X-factor determination in Alberta is unique because it utilizes a productivity value and a customer "premium." The latest productivity factor is based on three separate TFP growth studies, which the Commission noted provide an indication as to the range of acceptable productivity trends. The "premium" component functions like a "stretch" factor, which is meant to ensure ongoing customer-benefits sharing by way of improved utility productivity.
Connecticut	To be set during rate cases	Will be set by PURA (regulator) in rate amendment proceeding. Utilities are invited to provide a total factor productivity study in the course of rate case proposals that inform base rate setting and final MRP design. Studies must adhere to guidance from the regulator and will be subject to transparency requirements for intervenor review and counter-proposals.
Great Britain (RIIO)	1.0% (proposed)	The ongoing efficiency adjustment, proposed by the regulator, is set for RIIO-3 price control, where the regulator took into account quantitative and qualitative factors, including a productivity study that found historical productivity growth between 0.1-1.3%.
Hawaii	0%	The Commission asserted that setting the X-factor to 0% for the first MRP term is appropriate as the state transitions its ratemaking framework. The Commission rejected conclusions from TFP studies provided by parties, finding that the peer utilities reviewed in those studies are subject to different cost-recovery structures and are not engaged in comparable transitions towards PBR.

[43] Crowley et al., "Performance-Based Regulation Report With Recommendations for the Maine Public Utilities Commission."

Practice in Select Peer Jurisdictions		
Massachusetts	To be set in MRP	The Department establishes X-factors in an MRP based on a number of considerations. Approved X-factors include 0.21% (National Grid, electric), zero (Eversource Energy, electric), -1.18% (Eversource Energy, gas), and -1.30% (National Grid, gas).[44]
Ontario	0.15% for transmission; 0.45% for distribution	Following utility-proposed X-factors (separate for transmission and distribution system costs) and intervenor studies suggesting alternatives, adjustment rates were agreed in a settlement agreement for Hydro One electricity rates for the 2023-2027 period.[45]

Stretch factor (S-factor)

A stretch factor (S-factor), sometimes called a customer dividend, is an additional variable that can be employed in an ARM for the dual purpose of promoting additional productivity gains above and beyond the utility's peers and to create identifiable customer benefits. The "stretch" of this factor makes additional downward adjustment on allowed revenues, whether as an overall decline compared to beginning rates, or more likely to bend down the upward trajectory that is occurring due to other factors. This can be enacted as a one-time downward adjustment, or it can be built in as an annual (recurring) adjustment.

The stretch factor, especially when expressed in the language of a customer dividend, provides an attractive tool by which a regulator can demonstrate its commitment to cost containment and affordability objectives. In the context of an index-based ARM, it is employed as a numeric adjustment in a similar manner to I- and X-factor adjustments, as it gets embedded with other variables to create an algebraically derived impact on allowed revenue levels. In that application, the S-factor has a positive value, while it is incorporated with a negative adjustment similar to the X-factor.

Alternatively, a customer dividend can be applied in a more conceptual manner, in which a "refund" to customers is ordered (either one-time or on a recurring basis). In that respect, the customer dividend is not limited to the domain of index-based MRPs but is a tool by which regulators can promote or elevate rate reduction and customer benefits of any regulatory structure.

[44] MDPU, "Petition of Massachusetts Electric Company and Nantucket Electric Company...," 82-84.; MDPU, "Petition of NSTAR Electric Company, doing business as Eversource Energy...," 57.; MDPU, "Petition of NSTAR Gas Company doing business as Eversource Energy...," 84.; MDPU, "Petition of Boston Gas Company, doing business as National Grid...," 83.

[45] Canada. Ontario Energy Board, "Decision on Settlement Proposal and Order on Rates, Revenue Requirement and Charge Determinants," Case No. EB-2021-0110, (November 29, 2022), https://www.oeb.ca/newsroom/2022/oeb-issues-decision-hydro-ones-first-combined-transmission-and-distribution-rates.

Practice in Select Peer Jurisdictions		
Alberta	0.3%	Alberta applies a "premium" to its X-Factor (discussed above) that is functionally similar to a S-factor for productivity. The 0.3% premium is added to the productivity factor of 0.1% to result in an X-Factor of 0.4%.
Connecticut	Optional	The regulator can adopt an S-factor as part of the Revenue Cap Formula, based on the findings of a peer benchmarking study. Utilities found to be efficient would receive an S-factor of zero (no adjustment), while inefficient utilities could receive a positive S-factor to create additional cost efficiency.
Hawaii	0.22% + $25 million savings commitment	The percentage adjustment is applied annually to the portions of the revenue formula that are subject to compounding (including initial revenue and I-factor), while an additional $25 million annual Savings Commitment for the duration of the MRP term was based on an independent management audit that identified savings opportunities available from business improvements.
Ontario	0.2% for transmission; 0.2% for distribution	Similar to X-factor determinations, S-factors were agreed by settlement for Hydro One following utility-proposed rates to apply separately to each of transmission and distribution capital costs.

Growth factor (G-factor)

Some index formulas include a growth factor (G-factor) to adjust for changes in the number of customers. This is meant to recover costs that scale with additional customer accounts and can be included to reflect uncertainty at the time that going-in rates get set for the total system size to be served by the utility. On account of the G-factor, indexes are sometimes referred to as "I-X+G." The G-factor is not applicable to a price cap index because revenue should scale with increased sales and customer charges, while rates are fixed by the index. Even under revenue cap indexes, some regulators have elected not to include a growth factor, for various reasons, including a view that cost increases due to more customers above forecasted should be modest and that other upward adjustment factors should be sufficient to absorb these costs.[46] Exclusion of a G-factor can also have a similar effect as an S-factor—reflecting the cumulative impacts and balancing act that designing an ARM must work through.

Capital adjustment factor (K-bar)

A capital adjustment factor, or "K-bar," is an indexing tool that can be built into an ARM to designate a revenue amount for cost recovery of new capital expenditures, applied separately from the productivity factor adjustment rate. This separate treatment can be useful to account for large capital investment requirements that utilities face, which have grown larger in recent years and have unique considerations compared to other utility costs. Depending on its design and scope, a K-bar might reduce the cost-containment pressure that could exist in a more consolidated ARM. It can

[46] CT PURA, "PURA Investigation into Revenue Adjustment Mechanisms...."

also diminish opportunities or interest in finding alternative solutions to capital expenditures, such as through non-traditional programs or operating solutions. However, a K-bar arguably maintains a cost-containment imperative compared to other capital funding mechanisms, such as cost trackers, while accounting for conditions that influence capital expenditure.

If truly an indexed adjustment, the K-bar would be set to a fixed numeric factor, such as a value derived from investment levels in past years. That approach can help to maintain cost discipline in capital spending during the MRP period. In reality, capital investments and their costs are lumpy and increasingly span a wide range of costs or technology types. As a result, K-bar adjustments have perhaps the least convergence on agreed methods or an identifiable options set compared to other index-based adjustments. Increasingly, capital cost adjustments occupy a large amount of attention and debate among regulators and stakeholders, and many expected or proposed costs during the MRP period become subject to additional investigations to judge prudency.

A K-bar is only one among many mechanisms employed to recover additional capital expense. For example, infrastructure projects can also be tracked via designated cost trackers, sometimes in the same regulatory regime that uses a K-bar and other capital cost recovery mechanisms. In some cases, these mechanisms can be subject to shared savings mechanisms (SSMs) or other performance incentives.

Due to their outsized importance and the significant debates associated with capital expense requirements, capital funding mechanisms receive additional attention below, separate from capital adjustment factors used in ARMs.

Adjustments for unanticipated events (Z-factor)

A “Z-factor” is a provision in an index-based cap MRP to allow rate adjustments in the event of an extraordinary, unforeseen event that has a material impact on costs or revenue. Events of this nature can include natural events (wildfires and associated liabilities), economic changes (effects of a recession), and major public policy (tax law changes). Rather than prescribe what events are eligible and what adjustments would be warranted, Z-factors are generally adopted as a set of guidelines and guardrails for how they can be used. Ultimately, it will be up to future regulatory discretion if a Z-factor event is triggered and what adjustments are warranted.

One consideration is what size of cost, or materiality, justifies Z-factor attention. Generally, smaller costs, such as those incurred for power restoration after small or medium storms, are not considered extraordinary and can be managed within the budgeted revenue that the utility collects. But the threshold can be murky and subject to debate in the wake of an event. To remove uncertainty, jurisdictions can adopt materiality thresholds at the time of MRP development, which serve as criteria for whether to consider Z-factor adjustments, and can be defined relative to a utility's annual revenue requirement. Some of these thresholds are listed in the table below. Other guidelines and Z-factor criteria are similarly useful to establish in advance of the MRP period to put in place fair practices for their use. A well-structured Z-factor can provide fair and constructive adjustments within an MRP period in the case of unusual circumstances, without necessitating a full off-ramp from the MRP.

Practice in Select Peer Jurisdictions		
	Materiality Threshold (Pct.-based equivalence)[47] and Additional Detail	
Alberta	0.4%	Costs recovered under this provision must be incurred prudently because of events outside the utility's control where the utility would not have a reasonable opportunity to recover these expenses otherwise. In addition, the Commission-set materiality threshold is determined by the dollar value of 0.4% of the ROE, which is indexed to annual MRP revenue updates.
Connecticut	0.75%	Would adopt Hawaii's Z-factor guidelines, with modification including to materiality threshold. Utilities can seek Z-factor adjustments in annual MRP compliance filings.
Hawaii	0.2 – 0.28%	Dollar-based thresholds set separately for each utility based on business size, ranging between $1 million to $4 million. Includes Z-factor guidelines, specifying that costs must be due to events outside the control of a prudently operating utility, and costs must not be recoverable through existing rates and other sources of revenue available to the utility.
Massachusetts	0.13%	The Department has found an "exogenous cost significance threshold" of 0.13% of a utility's total operating revenues, which is adjusted annually by the GDPPI, as eligible for consideration under the Z-factor. Types of applicable costs include changes in tax law, accounting, or judicial, regulatory, and legislative changes that uniquely impact the industry.[48]

Other exogenous costs (Y-factor)

Some ARMs, notably Alberta, include a "Y-factor" to recognize costs with exogenous determinants that are incurred regularly (unlike Z-factor costs, which are one-time and not anticipated). Inclusion of these Y factor costs in the ARM provides for a more transparent or intentional accounting structure to recognize cost recovery for these expenses that may be outside of management control, such as fuel cost recovery or purchased power. In most or all cases where there is no Y-factor explicitly included in an ARM, these types of costs still exist and are treated outside of the revenue or price cap, often in the form of cost trackers or variance accounts.

[47] Percentage-based materiality thresholds presented here (except for Massachusetts) are taken from Connecticut PURA Proposed Final Decision (page 26, footnote 27). In some cases, these are calculated percentages, derived from dollar-based thresholds adopted by applicable regulators in applicable jurisdictions.

[48] MDPU, "Petition of Massachusetts Electric Company and Nantucket Electric Company...," 94–95.; MDPU, "Petition of NSTAR Electric Company, doing business as Eversource Energy...," 73-74.; MDPU, "Petition of NSTAR Gas Company doing business as Eversource Energy...," 93-94.; MDPU, "Petition of Boston Gas Company, doing business as National Grid...," 94–95.

Capital Funding Mechanisms

Utilities across the country have proposed increased capital spending programs for a wide variety of infrastructure needs, ranging from grid modernization to grid upgrades and hardening (including distribution line undergrounding), to advanced metering, transmission buildout, large new generation projects, and more. MRPs provide a structure by which to encourage cost containment in capital spending programs, but they require careful and strategic design attention to account for the many ways (or accounts) through which the utility is managing capital projects and the embedded incentives of each. On the one hand, an MRP with overly strong cost containment could result in revenue deficiencies if a revenue cap does not anticipate or account for large capital outlays in future years. Similarly, an indexed cap may not be appropriate for the variable nature of capital expenditures. On the other hand, too much flexibility, or automatic adjustments such as through cost trackers, can diminish incentives for finding cost efficiencies. Also, spreading capital projects into too many special-purpose cost recovery mechanisms (i.e., "single issue ratemaking") leads to accumulating, disconnected cost recovery structures that miss the opportunity to manage capital budgets on a broader, enterprise-wide basis that forces strategic decision-making.

To build more effective incentives for utility capital expenditures, an MRP should be designed with visibility and attention to the full picture of current rate base, ongoing capital projects, and potential additional investments during the MRP period. An ideal structure might place all capital expense into a single capital budget with a strict revenue cap (or potentially a combined capital and operating budget, such as a total expenditure [Totex] approach), thereby forcing strategic investment decisions and innovative solution development. This may not be practical, however, especially in a period of growing needs and demand for grid investment across many areas. Instead, a more nuanced, hybrid structure can be warranted that combines two or more mechanisms. These can include performance incentives (e.g., SSMs or support for operating expense alternatives like non-wire solutions). In addition, past regulatory decisions and project approvals, or statutorily required investments, may have created legacy mechanisms and billing features that are not feasible to immediately consolidate into a preferred regulatory framework.

In addition to a K-bar mechanism, three other capital recovery approaches are common under MRP structures:[49]

- **K-bar:** Adjustment factor set based on historical capital expenditures (discussed in greater detail above under *Attrition Relief Mechanisms*).
- **Forecasted capital:** The utility estimates its necessary capital expenditures for the MRP period, which informs a capped revenue allowance for those projects during the period.
- **Capital trackers:** Annual cost trackers allow recovery of actual costs incurred.
- **Project- or program-specific cost recovery:** Allow recovery of costs incurred for designated projects or capital funding programs, subject to certain criteria.[50]

[49] Adapted from Crowley et al., "Performance-Based Regulation Report with Recommendations for the Maine Public Utilities Commission."

[50] "Alternative rate mechanisms," as have been used and proposed in Oregon, can take the form of project- or program-specific cost recovery. See, for example, Docket No. UG 527 (Northwest Natural Alternative Rate Mechanism), and Docket No. UE 459 (PGE Application for Distribution Plan Alternative Rate Mechanism).

Of these, K-bars or forecasted capital budgets (in which a capped budget is permitted for capital expense) can incentivize greater cost efficiency compared to trackers, where cost recovery may occur in a more "pass-through" approach to collect from customers. In reality, each approach can have lesser cost-containment incentives (for example, if forecasted costs are inflated) or greater incentives (for example, if an SSM is applied to a capital tracker).

As this discussion reveals, many variants on these mechanisms are possible, and MRPs frequently employ hybrid forms or combinations of these. This is practical to account for inherent uncertainties related to capital expenditures, including the reality that resource planning and capital projects may be in a developmental stage or subject to regulatory review at the time the MRP going-in rates and adjustment factors are set. This requires a balancing act and thoughtful connections to get made between revenue setting, planning studies, and utility information sharing.

Massachusetts illustrates some of the many ways in which capital funding mechanisms get constructed, with unique combinations among utilities in the same state. For example, National Grid employs a capital recovery mechanism for its electric utility, the Infrastructure, Safety, Reliability, and Electrification (ISRE) mechanism, that is outside the indexed-based revenue cap. The DPU stated that, "[c]apital trackers like the ISRE mechanism provide rate relief between base distribution rate cases to fund capital investments that would otherwise be funded through sales growth."[51] Annual increases in the revenue requirement for the ISRE mechanism are capped at 3%.[52] In its decision on the utility's MRP, the Department rejected the utility's proposal for a Y-factor, which would have recovered capital-related O&M expenses.[53] By comparison, Eversource Energy's electric utility includes a K-bar in its index-based MRP, which is based on an annual rolling average of the rate base included in the revenue requirement. If actual capital expenses exceed forecasted expenses, the K-bar is capped at a 10% variance.[54] Eversource also has project-specific cost trackers.[55] National Grid's gas utility is permitted to incorporate post-test-year plant additions into rate base from a nine-month window after the test year, and is directed to adjust going-in rates for several factors related to its assets, including depreciation expenses and associated taxes.[56] In recognition that additional capital costs are incorporated into going-in rates, the Department limited the utility's Z-factor to exogenous costs on O&M cost categories and excluded the utility from filing for adjustments to the annual revenue requirement of cumulative capital investment.[57] Eversource Energy's gas utility has also been permitted to update its rate base under its current 10-year plan period.[58]

[51] MDPU, "Petition of Massachusetts Electric Company and Nantucket Electric Company...," 52.
[52] MDPU, "Petition of Massachusetts Electric Company and Nantucket Electric Company...," 49.
[53] MDPU, "Petition of Massachusetts Electric Company and Nantucket Electric Company...," 49, 52, 90-91.
[54] MDPU, "Petition of NSTAR Electric Company, doing business as Eversource Energy...," 61-64.
[55] MDPU, "Petition of NSTAR Electric Company, doing business as Eversource Energy...," 101.
[56] MDPU, "Petition of Boston Gas Company, doing business as National Grid...," 78-79.
[57] MDPU, "Petition of Boston Gas Company, doing business as National Grid...," 97.
[58] MDPU, "Petition of NSTAR Gas Company doing business as Eversource Energy...," 73-74.

Practice in Select Peer Jurisdictions		
	Notable Features	**Additional Detail**
Alberta	Two-tier approach, including a K-bar	Capital recovery methods have evolved with each successive PBR cycle in Alberta. Currently, "type 1" capital can be approved if extraordinary and outside normal operations, while other "type 2" capital is subject to a K-bar based on a 5-year historical average adjusted for customer growth and a productivity factor to encourage cost containment. Type 1 projects are subject to a materiality threshold of 0.01% impact on ROE and must also consider operating expenditure (Opex) alternatives.[59]
Connecticut	Customized K-bar ("CT-bar") plus separate capital cost trackers	Adopts a two-part structure for capital funding: a "CT-bar" for incremental capital expenditures that are not captured in the Revenue Cap Formula, and additional capital cost trackers for occasional cases limited to "only discrete, extraordinary cost recovery purposes" such as Advanced Metering Infrastructure deployment. The CT-bar would apply a 9-point guideline for approval and recovery, including a 6-step calculation methodology and expectation that covered capital expenses transition into base rates in the next rate case. For other capital cost trackers, PURA requires limited uses only after it is found to not be appropriate for recovery through base rates or other revenue requirements.
Great Britain	Totex accounting	Among other features, uses a Totex approach to combine capital and operating expenses into a common budget. This helps to reduce capital bias, giving the utility an interest in seeking alternative (operating) solutions to capital projects.
Hawaii	Exceptional Project Recovery Mechanism (EPRM)	The EPRM replaced the "Major Projects Interim Recovery" to permit investments that go beyond "business as usual" expenses and to support exceptional projects that align with regulatory or policy priorities. Guiding principles set by the Commission dictate that EPRM applications be considered on a case-by-case basis, with no monetary threshold for capital projects. EPRM can also consider projects with non-capital expenses if they are at least $2.5 million.

[59] Goldenberg et al., "Fixing Multiyear Rate Plans: Building a firm foundation for utility cost control," Appendix A.

Massachusetts	Utility-specific approach	The Department has approved a K-bar or a capital tracker for core capital investments by multiple utilities.[60] Certain utilities with a K-bar also have project-specific capital trackers, such as for grid modernization or vegetation management.[61]
Washington	Utility-specific approach (subject to change)	The UTC has not adopted a universal approach to capital funding mechanisms but has stated its intent to release a regulatory assessment policy paper in 2026 to evaluate all existing capital funding and reconciliation mechanisms, their interactions with MRPs, and whether changes are warranted.[62]

Reconciliation Mechanisms

MRPs can sometimes incorporate other revenue adjustments, related to capital funding and other mechanisms described in this report. In some instances, these take the form of "reconciliation mechanisms" to provide true-ups between target revenues set in a rate case to actual costs incurred. In general, reconciliations of this type diminish cost-containment incentives faced by the utility, because they can serve to turn a revenue cap into a flexible target that adjusts to whatever costs are incurred.

Maryland's "MRP Reconciliation Mechanism" is an example, which has been heavily criticized by the state's consumer advocate (Office of People's Council) and other intervenors. The MRP reconciliation in Maryland provides an annual true-up of allowed revenue (which was set at the start of the MRP period and based on expected utility costs) with *actual costs* that occur during the prior year. This leads to a rates adjustment, upward or downward, in the form of a rider that is incorporated into future customer bills. Experience with the MRP Reconciliation Mechanism in Maryland demonstrates an overriding tendency for large upward adjustments to utility allowed revenue.

[60] MDPU, "Petition of NSTAR Electric Company, doing business as Eversource Energy...," 61.; Massachusetts Department of Public Utilities, "Petition of Massachusetts Electric Company and Nantucket Electric Company...," 46, 49, 52.

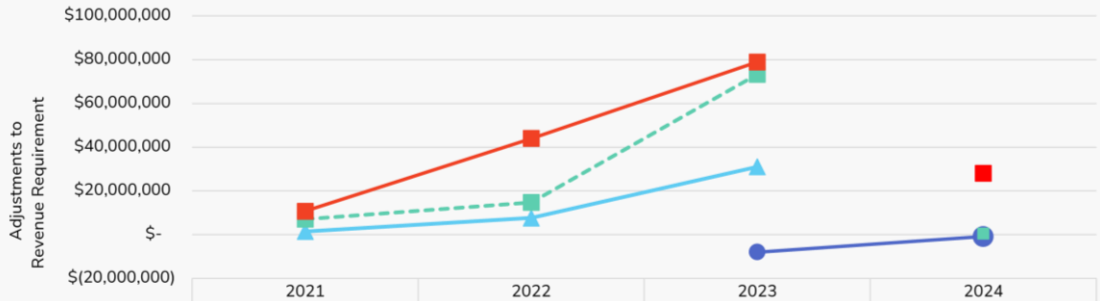
[61] MDPU, "Petition of NSTAR Electric Company, doing business as Eversource Energy...," 77, 101.

[62] Washington Utilities and Transportation Commission, "Proceeding to develop a policy statement addressing alternatives to traditional cost of service rate making, including performance measures or goals, targets, performance incentives, and penalty mechanisms," Performance Based Regulation Workshop presentation in Docket U-210590 (December 2, 2025), 19-21, https://apiproxy.utc.wa.gov/cases/GetDocument?docID=428&year=2021&docketNumber=210590.

Figure 3 shows the size of annual adjustments filed by several Maryland utilities operating under MRPs in recent years. In this chart, the deviation from the $0 value on the Y-axis indicates the amount of revenue adjustment collected by the utility, above or below the amount that was approved in the rate case for the applicable rate year. As seen here, these have consistently resulted in higher revenue for the utilities, due to higher-than-anticipated costs. Only Delmarva Power reflects an exception to this pattern, for which the adjustment is moderately negative and results in a small bill credit to customers.

The other utilities, notably demonstrated by Baltimore Gas & Electric (BGE), were permitted to collect significant additional revenue above the MRP-approved annual amounts. In fact, those adjustments get larger in each successive year of the MRP. In BGE's case, this added more than $133 million of additional electricity revenue due from customers during the MRP 1 period (rate years 2021 – 2023), and $95 million due from gas customers. This is the opposite of a revenue cap; rather than provide a budget by which the utility needs to manage its costs, the reconciliation mechanism adjusts revenue to whatever costs are incurred (subject to *ex post* prudency reviews). Maryland's OPC found similar results as those shown here, concluding that BGE overspent on Capex by 25% in 2022, and almost 45% in 2023.[a] As evidenced by the dots for 2024, BGE appears to be making similar upward revenue adjustments in its second MRP cycle (MRP 2) for both electric and gas revenue.

Figure 3: Annual Revenue Imbalances Subject to MRP Reconciliation in Maryland [b]



	2021	2022	2023	2024
Pepco - MRP1	$1,488,000	$7,611,000	$31,000,000	
Delmarva - MRP1			$(8,021,675)	$(855,406)
BGE Gas - MRP2				$458,000
BGE Gas - MRP1	$7,117,000	$14,786,000	$73,338,000	
BGE Electric - MRP2				$27,973,000
BGE Electric - MRP1	$10,711,000	$43,945,000	$78,938,000	

Year

Sources:
a. Based on Exhibit 3 of Goldenberg et al., "Fixing Multiyear Rate Plans: Building a firm foundation for utility cost control," 28-29.
b. CEG analysis of Maryland utility filings. Annual Utility Imbalances are obtained from Annual Informational Filings (AIFs) submitted by BGE, Delmarva, and Potomac Electric Company (Pepco) in each year of their respective MRP terms. Attachment 1 in each AIF lists the annual and cumulative revenue requirement imbalance over the MRP term. See ML# 308670 for an example of BGE's electric and gas revenue requirement imbalances for the first year of their pilot MRP term.; Public Service Commission of Maryland, "2023 Annual Informational Filing," Case Nos. 9618, 9645, (Baltimore Gas and Electric Company, April 1, 2024), Mail Log #308670, https://webpscxb.psc.state.md.us/DMS/maillogsearch.

The Maryland experience is a stark illustration of the pitfalls of making MRP revenues overly flexible. Rather than allow too many adjustments of this nature, more strict controls are appropriate, and adjustments should generally be limited to exogenous factors that are more definitively outside the utility's control.

Rebasing

Rebasing is the process by which going-in rates are reset at the end of the plan term to determine allowed revenues or prices for the next MRP cycle. After a period in which revenues have been de-linked from costs, rebasing provides a review to evaluate the performance of the MRP cycle that is concluding, as well as to set appropriate future utility revenues that ensure fair cost recovery continues, while maintaining or improving utility service and other objectives.

The methods and inputs to the rebasing process require careful consideration to balance utilities' interests in increased earnings with avoidance of perverse outcomes. For example, regulators and some intervenors may be tempted to "claw back" high earnings if a utility displays costs well below cost expectations that informed the previous cycle. However, this claw-back could be ill-advised if it would diminish the utility's faith in the MRP's incentives, and therefore diminish their motivation to pursue cost-efficient operations in the future. Meanwhile, utility management may lose their motivation to reduce costs in later years of an MRP stay-out period because they do not want to demonstrate too much cost reduction and reveal that lower allowed revenues are feasible in the next period.

As a result of these economic and strategic dynamics, it is helpful for regulators to set general parameters for how rebasing will occur but retain discretion to make adjustments or collect additional information based on conditions and utility performance that unfold in the period. Rebasing can also incorporate other MRP features that encourage continued pursuit of cost-efficient business operations, such as an efficiency carryover mechanism.

In Connecticut, regulators signaled their expectations for how rebasing and the transition from one MRP cycle to the next will occur. As illustrated in the following graphic, included in Connecticut PURA's *Proposed Final Decision* to establish their PBR framework, going-in rates are established via a rate case in the year preceding each MRP period, based on a utility-filed rate application. In addition, PURA plans a management audit in year three of the four-year MRP cycle, which will evaluate how well the utility is meeting regulatory objectives and identify if additional business improvements may exist to inform the next cycle.

Figure 4: Illustrative MRP Timing and Transition Process Between Periods (as expressed by Connecticut PURA)

Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
MRP 1					
Rate Case Proceeding (i.e., electric distribution company [EDC] files rate application on Year 1, Day 1)	Rate Year 1	Rate Year 2	Rate Year 3	Rate Year 4	
MRP 2					
			Management Audit Performed	Rate Case Proceeding	Rate Year 1

In contrast, the Hawaii PUC chose not to pre-determine the format and details for how rebasing and plan updates would be made at the conclusion of the MRP period, expressing that "prescribing

the end of the MRP too far in advance may inadvertently provoke gaming." Rather, the Commission said a review process would occur in Year 4 of the 5-year plan, which could take the form of a full COSR rate case or a different approach, subject to circumstances at that time.[63] When Year 4 came, stakeholders were invited to submit comments and attend workshops hosted by the Commission in their consideration of rebasing approaches. In early 2025, the Commission decided that a traditional COSR rate case proceeding would be used to rebase revenues for the next MRP. The proceeding will be split into two distinct tracks, one focused on the utility's revenue requirement, the other focused on revenue allocation and rate design for customer classes.[64]

Practice in Select Peer Jurisdictions		
Alberta	Rate case proceedings	The Commission initiates a general COSR proceeding prior to the conclusion of the ongoing MRP term. Rates are set based on a single forecast year and compared with actual costs to assess their reasonableness.
Connecticut	Rate case proceedings	Utilities would file a rate case at the beginning of the final year of each MRP, the determinations of which serve to set new base revenue requirements for the next MRP cycle.
Great Britain (RIIO)	Business plan review process	Rebasing follows the same process as setting going-in rates from the previous cycle. Network companies submit business plans, which are subject to a consultation process with the regulator and receive stakeholder comments. Additional updates and refinements to the RIIO structure are considered in the concurrent consultation process.
Hawaii	A review process, with format and scope subject to future Commission decision	The Commission's order adopting the MRP did not commit to how rebasing would be conducted. Following a review process in 2024, the Commission determined that it will engage in a general rate case proceeding to rebase revenues, and the utility will be required to use a forward test year.

[63] Public Utilities Commission of the State of Hawaii (HPUC), "In the Matter of Instituting a Proceeding to Investigate Performance-Based Regulation: Decision and Order No. 37507," Docket No. 2018-0088 (December 23, 2020), 207-211, https://hpuc.my.site.com/cdms/s/puc-case/a2G8z0000007fLQEAY/pc21581?tabset-431dc=3.
[64] HPUC, "Addressing the Matter of Re-basing Hawaiian Electric's Target Revenues for The Second Multi-year Rate Period: Decision and Order No. 41575," Docket No. 2018-0088, (February 27, 2025), https://hpuc.my.site.com/cdms/s/puc-case/a2G8z0000007fLQEAY/pc21581?tabset-431dc=3.

Efficiency Carryover Mechanism

An efficiency carryover mechanism (ECM) is for the purpose of counteracting diminished cost-containment incentives in the later years of an MRP period. As discussed in the rebasing section, utilities can lose motivation to maintain cost-efficient practices as they approach the rebasing process to set going-in rates for the next period, because they expect that historical performance will significantly inform future revenue setting. Rather than squeeze additional cost efficiencies out of their business, utilities may strategically maintain higher costs to establish a higher revenue trajectory for the next period. In recognition of this dynamic, an ECM permits the utility to retain a portion of cost savings in those later years of the period, for example, in a carryover account that is distributed to the utility in the next period. In this way, an ECM is similar to a SSM, including the necessity to establish a baseline from which savings are measured.

ECMs have had a mixed reception by regulators, reflecting reluctance by some to manage complex incentives while having limited information to judge cause and effect. Nonetheless, regulators and stakeholders may consider the merits of an ECM and associated design options that can support long-term cost efficiency and innovation, as well as other objectives like Opex and capital expenditure (Capex) equalization. Whether or not an ECM gets incorporated into an MRP, the diminishing efficiency incentive that it seeks to address is important to contemplate in pursuit of a balanced, outcomes-oriented regulatory structure.

Practice in Select Peer Jurisdictions		
Alberta	Discontinued	The Commission previously permitted an ECM within prior MRP terms that allowed utilities to carry forward earnings for up to two years. However, the Commission removed the provision in the latest enacted MRP due to insufficient evidence indicating the ECM was a deciding factor in any utility operational plans or investment decisions, thereby concluding that the ECM did not provide sufficient incentive to impact utility performance.
Australia	Included	Applies a "calibrated ECM" to promote cost savings for both operating and capital expenditures, with estimated savings of greater than AU$1000 per customer per year.[65]
Connecticut	Excluded	PURA elected to omit an ECM from its initial MRP framework, concluding that the practical challenges of administering it outweigh the benefits. The regulator indicated that an ECM could be incorporated in future MRP cycles.

[65] "Consumer benefits resulting from the AER's incentive schemes: A report for Energy Networks Australia" (HoustonKemp Economists, March 8, 2022), https://www.energynetworks.com.au/resources/reports/consumer-benefits-resulting-from-the-aers-incentive-schemes/.

Practice in Select Peer Jurisdictions		
Hawaii	Excluded	The Hawaii PBR Framework does not include an ECM, but the Commission expressed interest in SSMs for some investments, including non-wires alternatives and renewable energy procurement, which provide an alternative means to promote cost savings.[66]

Off-Ramps and Reopeners

Off-ramps provide a path to reset rates or exit the MRP structure before the plan period is complete. Compared to a Z-factor, which permits rate adjustments for extraordinary events but within a plan period, an off-ramp allows a more complete review and remake of the MRP, if not a full return to traditional COSR. To maintain cost control, regulatory certainty, and other objectives of the MRP structure, off-ramps should only be taken in rare circumstances when ratepayer or utility health is at substantial risk. In some jurisdictions, off-ramp thresholds have been found to be too easily met, diminishing cost-containment incentives from the outset because utilities do not expect MRP structures to be enforced.[67] Like a Z-factor and many other MRP design elements, it is useful to define principles or the circumstances in which an MRP off-ramp can be taken.

A lesser version of a full off-ramp is a reopener. In this case, a single mechanism or limited issue review can be made to fix an identified flaw in the MRP structure. Reopeners can create significant resource requirements for the regulator and intervenors to investigate and weigh options, making them a challenging effort that should be avoided as much as possible. But they provide a tool for targeted fixes without broader changes mid-MRP. The regulator can elect to take a range of actions following a reopener, depending on the circumstances, including narrow design fixes, rate adjustments (credits or surcharges), or moving to an off-ramp.[68]

[66] HPUC, "In the Matter of Instituting a Proceeding to Investigate Performance-Based Regulation...," 150-154.
[67] Goldenberg et al., "Fixing Multiyear Rate Plans: Building a firm foundation for utility cost control."
[68] Crowley et al., "Performance-Based Regulation Report With Recommendations for the Maine Public Utilities Commission."

Practice in Select Peer Jurisdictions	
Alberta	Reopeners are allowed based on materiality thresholds, including bands on allowed ROE. Reopeners have been triggered in multiple instances; in one case, no adjustment was found warranted, while in a different case, a $71 million refund was awarded to customers of multiple utilities.[69] The Commission rejected an off-ramp provision in the first approved MRP case and, since then, has not enacted a comparable provision.
Connecticut	Would allow off-ramps based on adopted criteria for circumstances related to the utility's degraded financial conditions, windfall profits, or falling interest rates.
Great Britain (RIIO)	RIIO "uncertainty mechanisms" include an option for re-openers. To be considered, re-opener applications must meet the materiality threshold compared to base revenue.
Hawaii	Off-ramps are for the most extreme situations and only after the Commission has investigated and determined it is an appropriate remedy. Reopeners are explicitly permitted if (1) the utility's credit rating outlook indicates a rating below investment-grade, or (2) ROE within the ESM is in the outermost ranges of the sharing bands (both upside and downside).

Complementary Performance-Based Mechanisms

MRPs are rarely applied in isolation, independent of other reforms. More commonly, MRPs are a feature of a wider set of performance-based regulation (PBR) mechanisms. Those are largely beyond the scope of this paper but are briefly presented here to place MRPs within a family of complementary regulatory tools.

A three-part framework is helpful to organize available mechanisms and elements of an outcome- or performance-based ratemaking approach:

- **Revenue adjustment mechanisms** to maintain appropriate revenue levels for cost recovery, including associated mechanisms to adjust revenues and/or ensure customer protection. These relate to a utility's primary cost recovery and profit structures. They provide the primary ratemaking adjustments that balance utility and customer (ratepayer) interests to fairly collect target revenues. In the context of PBR, these include tools that shift revenue determinations away from a backward-looking view of costs and sales to a more future-oriented approach that incentivizes cost control. MRPs are a prominent structure among revenue adjustment mechanisms, onto which other mechanisms can be integrated.
- **Performance mechanisms** to promote priority outcomes through increased transparency to system outcomes, as well as rewards for good performance and penalties for

[69] Canada. Alberta Utilities Commission, "AUC-Initiated Review Under the Reopener Provision of the 2013-2017 Performance-Based Regulation Plan for the ATCO Utilities: Decision 23604-D01-2019," Proceeding 23604, (February 27, 2019), https://www2.auc.ab.ca/proceeding/23604/dispositions/50647/details.; Canada. Alberta Utilities Commission, "AUC-Initiated Review Under the Reopener Provision of the 2018-2022 Performance-Based Regulation Plans for ATCO Electric Ltd. and ATCO Gas – Phase 2: Decision 29064-D01-2025," Proceeding 29064, (May 28, 2025), https://www.auc.ab.ca/regulatory_documents/decisions/.

underperformance. Performance mechanisms provide targeted incentives for a utility to deliver desired outcomes that align with policy and customer priorities. Incentives can be reputational or financial. Financial incentives may be realized as *ex post* additions or subtractions to allowed revenues and earnings that were established in rate cases or in individual riders or cost trackers.

- **Other regulatory structures** to create new processes or institutional arrangements that update utility functions (or create new functions) in support of identified needs. The "other" category can include a collection of reforms that do not fit neatly within the prior two categories, but which seek to modernize utility practices or institutional structures and directly relate to essential system functions or objectives.

Each of these categories offers a set of ratemaking tools that can be applied in support of performance- or outcome-based regulations. Some are frequently used in support of an MRP, such as PIMs to serve as "backstop" support for foundational utility performance areas, or can be applied through integrated design, such as Capex/Opex equalization strategies. Additionally, tools such as revenue decoupling can provide true-ups that maintain utility revenue in line with target levels under a revenue cap approach.

The "Other" category provides a more varied set of options, which may broadly be grouped among alternative ratemaking or other novel reforms. This Other category reflects interests and opportunities to incorporate additional reforms to help achieve new regulatory objectives. A large and varied set of mechanisms can be included in this set (such as advanced rate design and pricing structures, updated planning methods, or new procurement strategies), depending on the context or objectives of the venue. In this report, we identify a limited set that may be relevant to Oregon circumstances, mainly for the purpose of giving context to the three-part framework.

The following table provides a sampling of mechanisms within each of the three-part framework.

Type of Mechanism	Example Mechanisms
Revenue Adjustment Mechanisms	MRP
	Allowed ROE and ESMs
	Capex/Opex equalization
	Revenue decoupling
Performance Mechanisms	Metrics and scorecards
	Performance incentive mechanisms (PIMs)
	Shared savings mechanisms (SSMs)
	Fuel cost sharing mechanisms
Other Regulatory Structures	Innovation programs (e.g., regulatory sandbox)
	All-source competitive procurement
	Independent energy efficiency utility

This paper does not consider these complementary PBR mechanisms and other structures in detail; however, we note that they can be directly supportive of MRP objectives or help calibrate and balance the incentives of an MRP structure. Two mechanisms warrant particular attention, because they can provide necessary fine-tuning or countermeasures to MRP incentives:

- **Revenue decoupling** can be necessary in a revenue cap MRP structure. A revenue cap sets target revenues to collect within an appropriate range, regardless of costs or sales volume, but

it is possible for the utility to over- or under-collect its target revenue due to sales fluctuations or other exogenous factors. Revenue decoupling serves to true-up utility revenues to their target level, thereby providing the utility revenue assurance so that they can focus on cost control. This is in addition to the benefit of decoupling to remove the throughput incentive to increase sales, making utilities more receptive to energy efficiency and other demand-side management solutions. Revenue decoupling should be designed only with consideration for other revenue adjustments that may be in place; for example, decoupling's purpose and fit get diminished if there are excessive other revenue reconciliations in place, such that the revenue cap is not appropriately fixed.

- **Performance-incentive mechanisms** (PIMs) create financial motivation to achieve targeted outcomes, which the MRP may not otherwise support. "Backstop PIMs" can be particularly important to include in MRP design, to ensure service quality is maintained (e.g., for reliability and customer satisfaction). In the absence of backstop PIMs, there is potential for underinvestment and neglect of utility services due to the pursuit of cost savings. Backstop PIMs are typically constructed as downside, financial penalties for underperformance on core utility responsibilities. Other PIMs, such as for new or emergent roles for the utility, such as DER utilization, more often have symmetric or upside-only incentives.[70]

In some peer jurisdictions, PBR mechanisms provide bedrock features of regulatory reforms, which are arguably as important to cost control and other objectives as the MRP itself. For example, Great Britain's RIIO regulatory model relies on a long-duration MRP price control period, while its Totex accounting methods serve as a linchpin mechanism to promote Capex/Opex equalization and alternative solutions development. RIIO also employs a "Totex incentive mechanism" (a form of an SSM) to distribute cost-saving benefits between customers and the utility.[71] Among many other provisions, there is a Strategic Innovation Fund to provide utilities a budget to undertake non-traditional projects in partnership with third parties.[72]

Related Ratemaking Structures

MRPs inextricably exist within a broader regulatory framework. That includes a broad set of structures under legislative and regulatory authority, various planning and approval processes, and the institutional and legal arrangements to which a utility is subject. MRPs usually do not govern these other structures directly, but they can have a significant influence on the overall incentive framework and resulting performance. Given their interactive effects, it is useful to identify related processes and revenue structures that operate for a utility, and how those relate to the MRP structure being established. In some cases, the absence of direct relationships or connections can be an issue for attention. For example, there may be significant separation between an MRP and other regulatory features, leaving large areas of the utility business unaffected by the intended incentive alignment of the MRP. This can be seen in cases where an MRP applies to utility base rates but excludes large portions of costs that are subject to separate cost trackers or other recovery mechanisms.

[70] Cara Goldenberg et al., "PIMs for Progress: Using Performance Incentive Mechanisms to Accelerate Progress on Energy Policy Goals" (RMI, 2019), https://rmi.org/insight/pims-for-progress/.
[71] Great Britain. Office of Gas and Electricity Markets, "RIIO-3 Draft Determinations Overview Document."
[72] Great Britain. Office of Gas and Electricity Markets, "Ofgem Strategic Innovation Fund," n.d., https://iuk-business-connect.org.uk/programme/ofgem-strategic-innovation-fund/.

This section identifies some related ratemaking mechanisms and processes to consider when designing an MRP structure. For each, regulators should consider what level of coordination and influence is appropriate between the MRP and the related mechanism, and how to make connections between the various elements.

Cost Trackers and Riders

Utilities have increasingly relied on cost trackers and riders to collect revenue outside of base rates. Cost trackers are a common tool of "alternative ratemaking," as they provide an alternative cost recovery approach to the standard general rate case procedural process, often with independent and sometimes lesser prudency review requirements. When applied to individual projects, programs, or discreet portions of the utility business, cost trackers function as "single-issue ratemaking." As the name suggests, this practice results in isolating portions of the utility's business and its investments into sub-components, rather than using more broadly applied regulatory reviews.

Cost trackers can be attractive to ensure cost recovery for priority investments and programs, or those with novel features and exogenous cost drivers that the utility may seek to de-risk. They can also allow the utility to recover costs more quickly, in some cases, if costs become an automatic pass-through or are subject to more frequent or less rigorous prudency reviews. This can benefit the utility through reduced regulatory lag; however, cost trackers may also introduce challenges, including less scrutiny or expedited review of costs, or add complexity due to different cost recovery methods used for different utility functions.[73]

Cost trackers may go by different names depending on the jurisdiction, and the general concept can include related ratemaking practices, such as deferrals (regulatory assets) that are not immediately reflected in customer-facing rates.

Riders function similarly to cost trackers and serve as the billing mechanism to recover costs that may also be subject to a tracker. Riders can also be used with many other ratemaking tools, including reconciliation mechanisms for revenue decoupling, or the collection of special-purpose charges to fund policy-driven programs. In this manner, some riders may directly relate to the MRP itself, serving as a mechanical feature that calibrates revenue collection, while others operate more independently from the MRP structure.

Some cost trackers and riders may be unavoidable in modern utility ratemaking and, in some cases, have justifiable purposes. For example, cost trackers may be used during a transition period to a performance-based framework with an MRP, when legacy ratemaking elements persist. They can also be justified for costs largely outside of utility control, such as fuel cost reconciliation mechanisms; although even these have opportunities for improved cost management, and could be subject to a SSM or fuel cost adjustment mechanism. In general, however, it is advisable to limit reliance on cost trackers outside the MRP structure.[74] At a minimum, MRP development should account for these to evaluate the aggregate incentive framework and find opportunities to align incentives on a broad basis.

[73] Costello, "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives."
[74] Goldenberg et al., "Fixing Multiyear Rate Plans: Building a firm foundation for utility cost control."

System Planning: IRPs, DSPs, and Clean Energy

Ideally, the revenue requirement subject to an MRP includes as broad and complete a set of utility costs and functions as possible, including existing operating costs, existing rate base, and planned or additional capital projects during the MRP term. This puts the utility's total revenue requirement under one regulatory framework and encourages cost management within that structure. In practice, it may be difficult to do so, for one or more reasons. Those can include:

- Uncertainty about future projects and their scope, as investments remain subject to separate planning proceedings that have not yet been filed or ruled upon;
- Uncertain future costs, as project budgets and construction timelines are subject to change during planning and construction;
- Potential for alternative solutions (e.g., non-wire solutions) to be selected instead of traditional capital projects; however, those pathways create their own uncertainty of whether they would be viable and at what cost; and
- Provisions in a state's statutory requirements or regulatory practice for used and useful standards, which can prohibit pre-approval of some project costs.

These factors speak to the dynamic nature of regulations, especially as they relate to the interplay between resource planning and procurement that takes place in integrated resource planning (IRPs), distribution system planning (DSPs), and related processes. Clean energy targets, including achievement of renewable portfolio standards, and grid improvements to accommodate demand-side resources as well as grid hardening measures, all contribute to this complex dynamic across regulatory activities as well.

There is no easy answer for how to most effectively integrate these related activities or requirements into an MRP. But they warrant attention to coordinate timing and sharing of information to calibrate revenue targets as well as incentive details. Where possible, known and measurable costs can be subject to going-in rate determinations or can be accounted for in capital funding mechanisms (possibly with performance-based incentives for cost efficiency). As feasible, and without undermining cost-containment objectives of a budget cap that may be in place, emerging grid investment needs and cost information can inform updates to allowed revenue within an MRP. Or those costs can be managed separately, for example, through a short-term cost tracker and balancing account, subject to incorporation in base rates in the next MRP period.

Peer jurisdictions manage this in various ways. The Hawaii PUC has sought to make explicit connections and updates between its performance-based MRP framework and a concurrent integrated grid planning (IGP) docket. The latest HECO MRP finds that the Commission may consider new pilot programs and a grid services performance measure in ongoing IGP proceedings.[75] In Connecticut, PURA launched a concurrent Integrated Distribution System Planning (IDSP) docket in which grid needs and associated cost forecasts are developed, and which would directly inform the proposed "CT-Bar" capital funding mechanism.[76] Recently in Maine, the PUC

[75] HPUC, "In the Matter of Instituting a Proceeding to Investigate Performance-Based Regulation...," 114, 173.
[76] CT PURA, "PURA Investigation into a Performance-Based Regulation Framework for the Electric Distribution Companies: Decision," Docket No. 21-05-15 (April 26, 2023), https://www.dpuc.state.ct.us/FINALDEC.NSF/5cb88b8d5493c31d852588db0067d96d/8cc969f62e0dcde58525899d004dd68d?OpenDocument&Highlight=0,21-05-15RE03.

dismissed a Central Maine Power rate case filing that sought historically large revenue increases over a 5-year MRP period, partly on the basis that the rate case was filed before a 10-year integrated grid plan, which commissioners considered out of sequence.[77]

Cost Allocation, Rate Design, and Customer Programs

Customers ultimately experience the costs of utility investment and operations through the rates they pay on their utility bill. This makes cost allocation and rate design of great importance. Likewise, associated customer touchpoints like bill payment plans are critical aspects of the utility business for attention. Typically, these are not directly affected by MRP design; however, they need attention to ensure fair and reasonable rates, including costs commensurate with the value of service.

The outcomes and performance of an MRP also appear in customer bills, sometimes directly. For example, regulators can decide to include certain riders or reconciliation mechanisms on a customer bill, such as those from revenue decoupling or true-ups from an ESM. In some cases, a performance-based MRP can also incorporate PIMs or other incentive structures that promote desired rate design outcomes. For example, PIMs can be designed for enrollment in a TOU rate or demand response program. All of these reflect the two-way, interactive nature of the revenue-setting process and how that is translated to customers.

Putting It Together

As evidenced throughout this report, building an MRP is an exercise in selecting from a menu of options, then thoughtfully constructing the pieces to work together in pursuit of a set of identified objectives. This section offers ideas and considerations for how the many design elements can be assembled, including foundational (core) requirements as well as more complete or holistic regulatory design considerations.

At the outset of a design process, it is useful to reflect on the conditions and expectations for regulation in the applicable jurisdiction, as well as how those conditions are shifting. Many MRP structures described in this report are constructs that were created years ago, and in some cases decades, often predating current circumstances on the energy system, including grid modernization needs, ambitious clean energy targets, abundant distributed energy resources potential, and heightened affordability concerns. In some instances, historical experience with common MRP elements may reflect a traditional industry structure of commodity delivery from central generators through transmission and distribution to end-use customers. Consequently, not all elements or historical “best practices” will necessarily be applicable given today’s expectations for a modernized utility system, including concepts to build a services-based utility model within a highly-distributed electricity system and decarbonized gas sector, while managing high investment needs.

In this manner, it is important to recognize the context and assumptions built into different MRP elements. For example, a productivity factor that is based on peer utilities that are not subject to comparable cost-containment incentives or operate in different market structures may not be

[77] Maine Public Utilities Commission Docket 2025-00218 Bench decision on November 18, 2025, as reported in Portland Press Herald.; Daniel Kool, “Regulators dismiss CMP’s controversial 5-year rate increase,” Portland Press Herald, November 18, 2025, https://www.pressherald.com/2025/11/18/regulators-dismiss-cmps-controversial-5-year-rate-plan/#read-free.

applicable. Instead, these and other tools should be carefully considered and adapted for current conditions and objectives. Each jurisdiction and its regulator has the responsibility and discretion to select MRP elements that fit their circumstances, then to customize their design to achieve desired results.

As discussed previously in *Scope and Application of MRPs*, MRPs can be constructed in a narrow or limited manner to make modest refinements to existing ratemaking practices in a jurisdiction. That approach might be practical to obtain some benefits from an MRP. A narrow approach may afford a simpler design process, allowing focus on a few key structural reforms. There is a risk, however, that a narrow MRP structure could fall prey to some of the challenges of poorly designed, non-integrated MRPs that this report has identified. Meanwhile, a more complete MRP design, including integration with surrounding ratemaking structures, provides an opportunity for fuller cost-containment incentives across the utility system and to enable an updated utility business model. That approach can be complex to undertake, however, and will require continued care and refinement over the years.

Core Design Standards

To realize the benefits of MRPs and, importantly, to avoid the challenges identified throughout this report, it is useful to define some minimum design standards. The following could serve as a minimum viable product to create constructive MRP designs that mitigate some of the more problematic practices seen in some cases. These serve only as a starting point for MRP design, but can help ensure appropriate attention and fundamental basics are in place. These are not meant to represent a "narrow or limited" MRP design, as was presented elsewhere in this report; rather, these requirements suggest foundational elements that merit attention to establish a functional MRP with a high potential for cost containment.

1. **A plan duration of at least three years**, to avoid plans that are too short and would fail to capture MRP benefits. Longer durations (e.g., four or five years) have merit for additional time for utilities to perform under the plan as well as to alleviate the administrative burdens of frequent rate cases.
2. **A revenue cap to provide an authorized, or target utility revenue for each year of the MRP period**, to serve as a budget against which the utility can make efficient business decisions and achieve cost savings. Price caps may be considered as well, although this maintains a throughput incentive to grow total sales in that structure and requires attention to mitigate this effect. The setting of the annual target revenue can be informed by a historical test year or forecasted future costs, but should not be based on actual costs incurred.
3. **Indexed adjustments for exogenous cost contributors**, including inflation adjustments. Thoughtful consideration as to whether and how to include other indexed adjustments, such as X- or S-factors, depending on regulatory objectives and balance with other features of the MRP structure (e.g., what types of costs are subject to MRP revenues, what is the risk profile and risk sharing of the MRP and adjacent regulations, etc.).
4. **A capital funding mechanism** to account for capital investments that are expected, or could be proposed, during the MRP period. Careful design is required to create a capital funding mechanism that maintains cost containment and other regulatory objectives of the MRP,

while incorporating constructive connections to utility planning and procurement processes and evolving grid needs.

5. **Limited use of adjustments or reconciliation mechanisms**, for costs more directly controlled by the utility, both within an MRP period and at the conclusion of the MRP period.
6. **Backstop PIMs to prevent service degradation,** such as for reliability and customer service. These can be downside financial penalties for core utility services to avoid perverse outcomes from cost-cutting strategies that the utility may otherwise employ.
7. **Balanced risks and benefits between utility shareholders and customers**, through joint attention to authorized ROE and risk-sharing mechanisms such as an ESM.

Additional MRP Best Practices

The preceding set of core features offers structural elements that can serve as the foundation for an MRP. Upon those foundations, additional regulatory mechanisms can be employed to improve and calibrate the MRP framework in pursuit of desired outcomes. Some of those "add-ons" are briefly listed here. Many of these are discussed in earlier sections of this report, while others (including broader PBR development) require fuller review to identify design choices and their suitability within a particular MRP framework. It is useful to consider these at the outset of an MRP development process, although it may not be practical or feasible to incorporate all objectives expressed here from the beginning. By necessity, some items and enhancements may be subject to attention in future proceedings or subsequent MRP periods.

1. **Design for expanded outcomes, in addition to cost containment and administrative efficiency.** MRPs are frequently employed as a core feature at the heart of a broader PBR structure that seeks to balance traditional regulatory objectives with expanded energy system goals. It is important to identify those goals, preferably a limited number in a prioritized format, to help guide and calibrate MRP design and its interaction with other regulatory structures.
2. **Incorporate performance incentives for additional priority outcomes.** In addition to backstop PIMs, a limited number of additional outcomes can benefit from PIMs or other incentive mechanisms to support their achievement. Those can be symmetric or upside incentives to promote new or emergent utility service areas, such as clean energy attainment or demand-side programs.
3. **Mitigate capital expenditure bias to address gold-plating or overbuilding.** Capex bias is induced by traditional COSR, due to allowed earnings on capital but not operating expenses, and can be exacerbated by excessive authorized ROEs.[78] No single solution can eliminate Capex bias, but tools include promotion of non-wire (or non-pipeline) alternatives, and Capex-Opex equalization strategies, including Totex accounting, as well as consideration to right-sized ROEs balanced with sharing mechanisms.
4. **Consolidate revenue recovery within the MRP structure.** An MRP can contain strong cost containment and other incentives, but those will only apply to projects and cost elements that are actually subject to base rates governed by the MRP. Where possible, it is

[78] Dunkle Werner and Jarvis, "Rate of Return Regulation Revisited."

constructive that the MRP should apply to as broad a set of utility costs and functional areas as possible. That can include migration of existing trackers and riders into the MRP structure. This should allow the utility to make strategic business and operational decisions that optimize across functions and business units.

5. **Apply additional performance-based mechanisms, beyond the MRP.** Where some costs and utility responsibilities may not be feasible to incorporate into base rates, regulators can consider if and what other performance structures are available for those. That may include SSMs or fuel-cost adjustment mechanisms on cost trackers, or a wide variety of other PBR design options.
6. **Promote innovation in the utility business model, as well as the broader energy system.** Where there is a recognized need and desire to update utility functions or roles (for example, to a platform model or integration of more demand-side solutions), some jurisdictions have included special funding mechanisms or a budget for this purpose.[79]

Alignment with Cost Containment and Affordability Objectives

Achieving MRP objectives for cost containment and business efficiency is not a foregone conclusion; rather, it requires strategic design of interactive parts of the regulatory structure and balancing of competing interests. As detailed above, the selection of an appropriate MRP structure and its respective design elements influences the level of cost containment it can achieve. Likewise, the completeness of rates incorporated into an MRP relative to the entirety of a utility's revenue and expenses implicates how holistically cost containment will be influenced.

MRPs can improve affordability relative to "business as usual" by slowing or limiting increases in customer rates and may result in additional savings to ratepayers. Many design elements will influence the affordability outcome, including going-in rates, the use and permissibility of revenue adjustment factors, determinations for the rate of return, and the manner in which an earnings-sharing mechanism is employed. Other important energy affordability objectives, including alleviating energy burdens or reducing disconnections, also require attention but may not be directly addressed through the MRP process. Further, as jurisdictions examine alternative regulatory approaches, it is important to note that ensuring affordability in rate-setting remains complex and resource-intensive under an MRP, similar to COSR.

To support the specific objectives for cost containment and affordability, in the context of their many disparate influences inside and outside the regulatory framework, MRPs can be a useful tool, but only if purpose-built for those aims and when supported by other elements of a constructive policy and market paradigm.

[79] Grace Relf et al., "Regulatory Sandboxes and Other Processes to Expedite Utility Adoption of Advanced Grid Technologies" (Lawrence Berkeley National Laboratory, June 2025), https://emp.lbl.gov/publications/regulatory-sandboxes-and-other.

Conclusion

This report presents numerous design elements to consider in any examination of MRPs. It provides a taxonomy of MRP types and available features, paired with a selection of relevant examples from peer jurisdictions, which the Oregon Public Utility Commission and intervenors may draw upon as they undertake the AR 676 proceeding (In the Matter of Rulemaking to Establish Multi-Year Rate Plan Framework) and related activities in fulfillment of HB 3179 and other legislative and regulatory needs. Application to Oregon will depend on subsequent deliberations in AR 676, including consideration of related statutory requirements as well as concept development and refinement by the OPUC and participating intervenors.

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Appendix A: Suggested Reading

This report seeks to provide a relatively short, accessible review of MRP design options that can serve as a reference for the OPUC and Oregon regulatory stakeholders as they undertake MRP development in the ensuing months. It attempts to establish a functional framework, set of terms, and design options, along with reference points that can support a more constructive dialogue between stakeholders and the OPUC.

The following reports and other sources provide useful additional reading to explore MRP options and learn from the experience of other jurisdictions around the U.S. and internationally. These resources have informed this report and can be referenced to build a deeper understanding of MRP choices and trade-offs.

- Ken Costello, "Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives" (National Regulatory Research Institute, April 2014), https://nrri.org/download/nrri-14-03-alternative-rate-mechanisms/.
- Cara Goldenberg et al., "Fixing Multiyear Rate Plans: Building a firm foundation for utility cost control" (RMI and Synapse Energy Economics, November 2025), https://rmi.org/insight/fixing-multiyear-rate-plans/.
- Nicholas Crowley et al., "Performance-Based Regulation Report With Recommendations for the Maine Public Utilities Commission" (Christensen Associates Energy Consulting, June 27, 2025), https://www.maine.gov/mpuc/legislative/reports.
- Connecticut Public Utilities Regulatory Authority, "PURA Investigation into Revenue Adjustment Mechanisms for a Performance-Based Regulation Framework: Proposed Final Decision," Docket No. 21-05-15RE01 (July 14, 2025), https://www.dpuc.state.ct.us/DOCKCURR.NSF/8e6fc37a54110e3e852576190052b64d/1555634f73ae53a685258cc7007a62fb?OpenDocument.
- Public Utilities Commission of the State of Hawaii, "In the Matter of Instituting a Proceeding to Investigate Performance-Based Regulation: Decision and Order No. 37507," Docket No. 2018-0088 (December 23, 2020), https://hpuc.my.site.com/cdms/s/puc-case/a2G8z0000007fLQEAY/pc21581?tabset-431dc=3.
- Great Britain. Office of Gas and Electricity Markets (Ofgem), "RIIO-3 Draft Determinations Overview Document," Consultation, (July 1, 2025), https://www.ofgem.gov.uk/consultation/riio-3-draft-determinations-electricity-transmission-gas-distribution-and-gas-transmission-sectors.
- Canada. Alberta Utilities Commission, "2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities: Decision 27388-D01-2023," Proceeding 27388, (October 4, 2023), https://prd-api-efiling20.auc.ab.ca/Anonymous/DownloadPublicDocumentAsync/794425.

Appendix B: Glossary

This glossary provides short, accessible definitions for common elements of multi-year rate plans and a limited number of related ratemaking terms. This can serve as a reference to help clarify meaning and align stakeholders to use terms in a similar manner. This does not provide a comprehensive glossary for performance-based regulation or other regulatory structures. Fuller details and important considerations for each term can be found in the main report, as well as in those references included among *Appendix A*: *Suggested Reading* and elsewhere.

Term	Definition
Attrition relief mechanism (ARM)	An MRP structure to address potential erosion of achievable savings by making periodic rate adjustments (usually annual) that are set by a predetermined formula and adjustment factors that are separate from actual costs incurred. Adjustments can be calculated according to external index values, preset values, or the incorporation of costs or savings due to extraordinary events. ARMs are commonly incorporated with, and sometimes used synonymously with, index-capped MRPs.
Capital cost tracker	A capital funding mechanism that recovers actual costs associated with capital expenses over the term of the MRP plan. Project costs are pre-approved by the commission and passed through to customers, with an annual true-up of actual expenses. Project-specific capital cost trackers are a variant that applies to specific, approved projects.
Capital funding mechanism	Ratemaking provision that allows the utility to recover costs associated with capital outside of the MRP's primary revenue components. Various methods may be used to calculate capital funding levels, including historical expense data, forecasted capital costs, or some combination of these.
Earnings sharing mechanism (ESM)	A provision to automatically share surplus or deficit earnings (or both) between utilities and customers that may result when the return on equity deviates from the regulator-approved target (e.g., allowed ROE).
Efficiency carryover mechanism (ECM)	Provision within an MRP that allows the utility to retain a portion of cost savings achieved from productivity gains during the last years of a rate period, which can be applied as additional earnings in the next rate period. An ECM can lessen the utility's diminished interest in achieving cost efficiency if they expect that savings will result in lower revenue in the next period.
Forecasted capital recovery	A capital funding mechanism that relies upon the utility's estimate of future capital costs to set allowed revenue for applicable capital expenses over the term of the MRP plan.

Formula-based rates	An approach for utility cost recovery where expenses within a rate period are automatically updated according to the utility's actual costs, including deviations from previously forecasted or approved costs. This is distinct from index-based cap or forecasted MRPs because revenue adjustments under formula-based rates are made after costs are incurred rather than fixed, pre-approved amounts or adjustments for external factors like inflation.
Going-in rates	Utility allowed revenue set for the first year of an MRP period, which serves as a baseline from which subsequent adjustments are made (e.g., via indexed adjustment factors or other methods). The going-in rates may be calculated from forecasted or historical costs, or both, which can take place in a recently approved rate case (e.g., a test year), a cost of service study, or another method.
Growth factor (G-factor)	Adjustment to a utility's target revenue within an MRP period that recovers costs associated with changes in customer count.
Index-based adjustments	Adjustments to a utility's revenue requirement that are based on pre-determined index variables, typically exogenous to factors directly in the utility's control (e.g., inflation, productivity factor, number of customers). Sometimes synonymous with an attrition relief mechanism.
Inflation factor (I-factor)	Adjustment to a utility's allowed, or target revenue within an MRP period, common in an attrition relief mechanism, that is made according to an external inflation index (e.g. Gross Domestic Purchases Price Index, also known as GDPPI). The I-factor adjustment is usually applied annually.
K-Bar	A capital funding mechanism that can be incorporated into an attrition relief mechanism, which provides revenue adjustments for capital spending based on separate determinants than those applied in an I-factor, X-factor, or other adjustments. A k-Bar typically relies upon historical capital costs to set a cumulative "allowance" for applicable capital expenses over the term of the MRP plan. The allowance provides the utility with incremental revenue support for ongoing capital outlays without requiring continual capital recovery proceedings.
Multi-year rate plan (MRP)	A ratemaking approach to set utility revenues by establishing base rates for a fixed multi-year term with periodic adjustments according to predefined factors that do not require reopening or initiating a general rate case during the plan period.
Off-ramp	A mid-period exit from an MRP that permits an overhaul or substantive changes to the regulatory structure due to unforeseen events or perverse outcomes. Regulators can set strict criteria by which a utility is permitted to propose an MRP off-ramp.

Plan duration	See *stay-out period*.
Price cap	A limit on rates and associated adjustments charged to customers that result from a settled rate case. Prices can be adjusted according to external index factors, like inflation.
Productivity factor (X-factor)	Adjustment to a utility's allowed, or target revenue, within an MRP period, common in an attrition relief mechanism, that reflects changes to utility sector productivity over time (ratio of inputs to outputs). The adjustment is applied annually during the stay-out period and can be based on a pre-determined value that is selected by the regulator and may be informed by a total factor productivity study or other economic analysis.
Rebasing	Process at the end of an MRP period that sets the going-in rates for the next MRP.
Reconciliation mechanism	Adjustment to a utility's revenue within an MRP period that reconciles differences between target revenue and actual costs incurred.
Reopener	A review made mid-period during an MRP to consider changes to allowed revenue or updates to mechanism design, as a result of unanticipated results. Conditions that may permit a reopener can include significant over- or under-collection of revenue, significant cost changes, or factors that would prevent a utility from achieving its authorized rate of return.
Return on equity (ROE)	The rate that a utility's shareholders expect to earn on the equity portion of capital expenses. ROE comprises one element of a utility's total authorized rate of return.
Revenue cap	A limit on the revenue that a utility is authorized to earn in a year. Revenue caps are typically adjusted annually according to external index factors, like inflation.
Revenue requirement	The aggregate revenue (typically measured on an annual basis) that a utility is allowed to collect in exchange for providing service.
Stay-out period	The length of time for which rates are set for a utility without an update in a general rate case. In MRPs, this can be a provision in a rate case decision that prohibits the utility from filing a new rate case for the specified duration of time (except in the case of an off-ramp or other event necessitating review). Also known as plan duration, MRP period, or rate period.
Stretch factor (also known as "customer dividend")	Downward adjustment to a utility's allowed revenue within an MRP period, in addition to I-factor, X-factor, and other adjustments, that seeks cost savings that are above and beyond peer utility productivity or due to other identified cost savings. These savings can be "returned" to customers in the form of lower rates than would otherwise occur.

Test year	The period in which a utility's costs and billing determinants are considered in a rate review. A historical test year uses information from a past period's costs and sales information, then adjusts costs for known and measurable changes. A forecasted test year uses estimates, or forecasts, for expected future costs to be incurred in the rate case period. Hybrid test years and other variants are possible.
Y-factor	Adjustment to a utility's target revenue within an MRP period that recovers costs associated with recurring expenses that are outside of a utility's control.
Z-factor	Structure within an MRP, common in an attrition relief mechanism, to permit adjustment to a utility's target revenue, that allows rate adjustments for unforeseen events outside utility control (e.g., catastrophic storms, wildfire, or policy change) that are not included in going-in rates or other adjustment factors. Regulators can set standards or criteria by which a utility is permitted to propose a Z-factor adjustment.

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