# Performance-Based Regulation Report With Recommendations

# for The Maine Public Utilities Commission

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# EXECUTIVE SUMMARY

The purpose of the study is to evaluate the Performance Based Regulation (PBR) tools that may be used to regulate investor-owned electric utilities (IOUs) in the state of Maine.

One of the central findings of this report is that the Maine Public Utilities Commission (MPUC) has already incorporated several PBR elements into its ratemaking structure. The MPUC currently regulates the state's IOUs with Performance Incentive Mechanisms (PIMs) in the form of Service Quality Indicators (SQIs), which apply to both utilities. The IOUs also have the option to file Multi-Year Rate Plans (MYRPs), such as Central Maine Power's (CMP) current MYRP and the company's former price cap. Furthermore, Maine's utilities have implemented other alternative regulation tools such as Earnings Sharing Mechanisms (ESMs) and revenue decoupling.

PBR tools have been used in other jurisdictions to address policy initiatives similar to the objectives of the MPUC. Some of these regulatory approaches could be introduced to Maine, and others that are optional could be formalized or made mandatory. For example, by formalizing a basic structure for MYRPs and requiring the state's utilities to follow this structure, the MPUC could create a regulatory framework in which utilities might gain more predictable revenues and obtain stronger incentives for cost control and innovation, while consumers might benefit from more stable rates, improved utility performance, and the potential for lower rates in the long run as efficiency gains are shared. New PIMs can be used to target specific policy objectives like resiliency, greenhouse gas emissions reduction, and renewable energy connections.

However, while the adoption of PBR tools may provide improvements to the status quo regulatory framework in Maine, the introduction of new PBR tools would not guarantee such improvements. The realization of benefits from PBR requires a well-structured design that accounts for the particular circumstances of the jurisdiction or utility. For this reason, while case studies offer valuable insights, a plan that was successful for one utility will not necessarily replicate that success if applied identically to a different utility or in a different jurisdiction.

### *Performance Incentive Mechanisms*

A PIM is a PBR tool involving an annual revenue adjustment mechanism that ties financial incentives to the achievement of pre-defined benchmarks or targets. PIMs can be reward-only, penalty-only, or symmetric, meaning they could result in both a reward and a penalty. Typically, PIMs operate by adjusting a utility's return on equity (ROE), though in some cases a pre-determined dollar value is used for a penalty or reward.

Generally, regulators and utilities institute PIMs after identifying specific, targeted policy goals related to utility outputs. This involves establishing metrics, defining achievement thresholds, and setting financial rewards or penalties. The implementation of PIMs requires careful design to ensure they effectively drive desired outcomes without unintended consequences. Key considerations include selecting metrics that are meaningful, measurable, and within the utility's control; setting challenging but achievable targets; and determining the magnitude of financial incentives that will motivate utilities without unduly burdening ratepayers.

One question about the design of PIMs is whether to make the financial incentive a reward, a penalty, or financially symmetric — meaning that the PIM offers a reward for positive achievement and a penalty of sub-par achievement. An approach to answering this question is to offer a reward if the utility has not been expected to produce the output in the past, since the cost is not reflected in rates, and a penalty if the utility is traditionally expected to provide the output.

The SQIs currently in place for Maine's utilities are PIMs in all but name. They have a clear performance target that the utilities must maintain and failure to maintain these performance targets results in penalties. Building on foundation established through existing reliability and customer service PIMs (SQIs), Maine could use PIMs to advance additional policy priorities and innovation. We recommend that the MPUC, the regulated utilities, and stakeholders collaborate to prioritize which policy goals (see Section 7.3) are currently unaddressed by the state's regulatory framework and establish metrics that reflect the achievement of these goals. Experience from jurisdictions using reward PIMs to promote key policy goals explored in Subsection 4.6 may be informative to Maine.

Table ES.1 offers recommendations regarding PIMs in Maine.

**Table ES.1: Recommendations for PIMs in Maine**

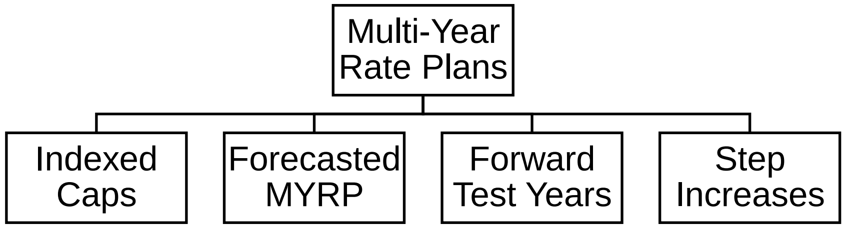
| | |
|---|---|
| Recommendations for PIMs in Maine | *1. We recommend that the Maine PUC allow the state's IOUs to file new PIMs as part of future rate applications, to be assessed on a case-by-case basis. We recommend using the guidelines provided in Section 4.2 in the design of these PIMs.*<br><br>*2. We recommend that before instituting any mandatory PIMs or any PIMs that apply to all IOUs, the Maine PUC determine which specific policy goals might be addressed by PIMs and meet with stakeholders to discuss potential benefits and drawbacks of attaching financial incentives to related metrics. We recommend following the criteria set out in Section 4.2 prior to implementing mandatory PIMs.* |

**Multi-Year Rate Plans**

MYRPs are a category of alternative regulation tools that provide a framework for setting rates that can reduce the frequency of utility rate cases, facilitated by rate adjustments that either follow industry cost and productivity trends or align with the company's own costs—actual or forecasted. Thus, rather than establishing static rates that remain in effect until a future rate case—as under traditional Cost of Service Regulation (COSR)—a MYRP sets a schedule or formula that allows rates to change over the plan period. It is not until the end of the MYRP period that rates are reset through a comprehensive cost-based rate case. Most MYRP terms last three to five years.

Figure ES.1 depicts several categories of MYRPs that are currently used by utilities in North America.

**Figure ES.1: Forms of MYRP**




The regulated electric utilities in Maine already have the opportunity to file MYRPs in the form of an Alternative Rate Plan, and as such, the state of Maine already has some past experience with MYRPs. Central Maine Power (CMP) operated under a price cap, which is a form of indexed cap, until 2013. CMP is currently operating under a two-year alternative rate plan.

Other jurisdictions, like those in Canada, Australia, and Great Britain, have developed standardized MYRP models that all utilities within the jurisdiction must follow. However, these jurisdictions generally contain many more distribution utilities than Maine. Rather than mandating a standard MYRP template that both utilities must follow, the MPUC could consider creating a general set of requirements that CMP and Versant Power must follow if they file a MYRP. This could be a highly structured, detailed set of rules that must be followed if the IOU elects to file a forecasted or indexed cap MYRP. Alternatively, the MPUC could adopt a high-level set of principles. Section 5 of this report contains recommendations for rules or principles to be followed for both indexed cap and forecasted MYRPs.

Cost efficiency incentives through MYRPs may help with affordability but will not resolve all factors driving customer rate increases. A substantial portion of rates paid by end users pertain to generation services, which Maine's IOUs do not provide.

Table ES.2, we encourage the adoption of forecasted and indexed cap MYRPs.

**Table ES.2: Recommendations for MYRPs in Maine**

| | |
|---|---|
| Recommendations for MYRPs in Maine | *Maine IOUs are already permitted to file MYRPs as an alternative rate plan. To provide cost efficiency incentives to the utilities, we encourage the adoption of either forecasted or indexed cap MYRPs.*<br><br>*Furthermore, we note that, as "lines-only" utilities, IOUs in Maine may be well-suited for indexed cap (price cap, revenue cap, or hybrid) PBR frameworks, as these plans provide cost efficiency incentives that may improve customer affordability. We therefore encourage the state's IOUs to voluntarily propose indexed cap MYRPs, and we encourage the Maine PUC to accept well-designed indexed cap plans (with further recommendations in Table 8.4).* |

**Other Alternative Regulation Tools**

The industry acknowledges that PBR is not a binary term, and that some tools that are considered "alternative" to traditional regulation do not necessarily provide enhanced efficiency incentives to utilities. Alternative regulation tools include formula rates, capital trackers, totex, revenue decoupling, ESMs. While these tools are useful in certain circumstances, their application does not necessarily provide the same enhanced efficiency incentives to utilities as, for example, indexed cap MYRPs.

Some of these tools, such as CMP's ESM and revenue decoupling for both IOUs, are already used in Maine. ESMs manage the risk of a utility over- or under-earning relative to its allowed ROE. Utilities operating with ESMs share earnings that exceed (or fall short of) a predetermined threshold, either reducing rates for customers in the case of overearning or, depending on the design, providing financial relief to utilities in the event of underearning. ESMs are a form of alternative regulation distinct from PBR because ESMs relink the utility's revenues and costs, removing or mitigating cost efficiency incentives. However, ESM are often included in PBR plans as a means of managing risk.

Revenue decoupling is a regulatory mechanism used in the electric utility industry to separate a utility's revenue from its sales volume. Traditionally, utility profits were directly tied to the amount of electricity sold, creating an inherent incentive for utilities to promote increased energy consumption. Decoupling breaks this link, allowing utilities to recover their fixed costs and earn a fair return on investment regardless of fluctuations in electricity sales.

# 1 INTRODUCTION

## 1.1 Background and Scope of Work

The Maine Public Utilities Commission (MPUC) has directed Christensen Associates Energy Consulting (CA Energy Consulting) to assist with examining performance-based tools for regulating the state's investor-owned transmission and distribution utilities. This report presents our findings and recommendations for the applicability of performance-based regulation (PBR) for the state's electric utilities. The study addresses Multi-Year Rate Plans (MYRPs) including indexed revenue formulas, and Performance Incentive Mechanisms (PIMs). These are, with minor exceptions, the primary PBR tools used by electric utilities in North America.

The purpose of the study is to evaluate the PBR tools that may be used to regulate investor-owned electric utilities (IOUs) in the state of Maine. The scope of work for this project includes:

1. Conduct a comprehensive review of the standards and metrics utilized in other states that have implemented performance-based rate design, including an evaluation of the outcomes that resulted from the imposition of performance-based standards and metrics on the utility;
2. Assist the Commission in developing goals for utility performance and translate these goals into performance-based standards and metrics;
3. Identify any emerging regulatory mechanisms that would better align utility performance with state policies and goals when compared to other traditional forms of regulation;
4. Participate in stakeholder meetings, where necessary; and
5. Provide a detailed report to the Commission.

To understand potential regulatory changes in Maine requires a review of current ratemaking practices by utilities within the jurisdiction of the MPUC. Identifying potential beneficial changes to this paradigm also requires a review of PBR tools and methods used in other jurisdictions, a discussion of related economic theory, and results from engagement with stakeholders in the state of Maine. Our approach makes recommendations for updates to the state's existing regulatory framework only after this analysis. For each PBR tool discussed herein, we also discuss best practices for implementation, weighing the costs, benefits, and risks.

The organization of the report is as follows. This first section of the report explains the reason for the report, qualifications of the research team, and recommendations for how to use the remainder of the report. Section 2 presents fundamental concepts of rate regulation, comparing and contrasting traditional regulation with PBR. Sections 3 through 5 present a description of typical PBR mechanisms, including discussions of the economic principles supporting each tool and a review of jurisdictions where those tools are currently in place. Section 6 describes other tools in alternative regulation. Section 7 provides an overview of Maine's current regulatory framework and assesses possible updates. Section 8 concludes with a summary of findings and our recommendations.

## 1.2 Qualifications of the Project Team

Christensen Associates and its wholly owned subsidiary, Christensen Associates Energy Consulting (CA Energy Consulting), have over 40 years of experience in the design and application of incentive regulation plans across network industries, including electricity, gas, telecommunications, and postal industries.[1] The key team members for the project are Mr. Nicholas Crowley, Dr. Sherry Wang, and Mr. Andis Romanovs-Malovrh.

Mr. Nicholas Crowley, CFA, is a Vice President with Christensen Associates and has been with the firm since 2016. He has filed testimony on incentive regulation in both the United States and Canada and has filed reports and testimony on incentive regulation in Ontario, Alberta, British Columbia, New Hampshire, and Massachusetts. Prior to joining this firm, Mr. Crowley was an economist in the Department of Pipeline Regulation at the Federal Energy Regulatory Commission (FERC), where he assisted with energy industry benchmarking, the price cap regulation of oil pipelines, and the review and evaluation of natural gas pipeline rate cases. In these roles, Mr. Crowley worked extensively with FERC data, and other federal data, for the development of cost benchmarks for power systems, in measuring industry Total Factor Productivity (TFP) growth, and the development of incentive regulation plans. Mr. Crowley has a Master of Science degree in economics and a Bachelor of Science degree in economics, both from the University of Wisconsin-Madison, and he is a CFA charterholder.

Xueting (Sherry) Wang, PhD, is an Economist. She has conducted research of Performance Incentive Mechanisms on behalf of both regulators and utilities. Dr. Wang also has experience in a variety of areas related to utility ratemaking including reviewing cost-of-service methodology, rate class determination, building rate design models, conducting bill impact analysis, and estimating customer load response to changing prices. Her doctoral research at Columbia University focused on energy and environmental economics.

Andis Romanovs-Malovrh is an Economist with Christensen Associates and has been with the firm since 2023. He has provided support in performance-based regulation projects in Ontario and Indiana and has assisted in extracting and processing utility factor productivity data. Andis also helps estimate load impacts in response to residential air condition load control and critical peak pricing programs as well as time-varying electric rates. Andis has a Master of Arts degree in economics and a Bachelor of Arts degree in economics from Riga Technical University.

Corey Goodrich is a Staff Economist at Christensen Associates. His work includes analyzing customer response to dynamic and time-vary electricity rates, evaluating load impacts of demand response programs, stakeholder feedback, and supporting utility rate applications. Prior to working at the firm, Corey worked in both academia and government. He has co-authored academic publications and performed evaluations of state workforce programs. His research has been published in journals such as *Applied Economics*, *Applied Economic Letters*, *and The BE Journal of Economic Analysis & Policy*. Corey has a Master of Arts degree in economics from the University of South Florida and a Bachelor of Arts degree in economics from the University of Wisconsin-Eau Claire.

[1] Network industries are characterized by product distribution lines connected by nodes that serve multiple distribution lines. Examples include electric and gas utilities, pipelines, telecommunications companies, railroads, and the U.S. Postal Service.

# 2 FUNDAMENTALS OF RATE REGULATION

## 2.1 Concepts in Traditional Regulation

Investor-owned utilities across North America face regulatory oversight vis-à-vis revenue recovery. Electric utilities and other network firms have traditionally operated under "cost-of-service regulation" (COSR), also known as "rate-of-return" regulation, in which firms submit an accounting of annual costs (i.e., revenue requirement) in periodic rate filings before their regulatory authority for approval. Rates are then set to recover approved historical accounting costs. Such an approach carries both benefits and drawbacks.

Utility regulation exists primarily because electric utilities, particularly transmission and distribution network operations, face limited competitive market pressures. These industries have high fixed costs and significant economies of scale that make competition impractical or inefficient. Regulation serves as a substitute for market competition by protecting consumers from the price implications of this market power while ensuring reliable service and adequate infrastructure investment.[2] Regulatory frameworks aim to balance the public interest with reasonable returns for utility shareholders, while addressing externalities and public policy objectives that markets might not adequately account for on their own.

Electric utility rates are regulated through a formal rate application process commonly referred to as the "rate case".[3] A rate case is a formal regulatory proceeding where a utility requests approval to change its rates. The process typically begins with the filing of the utility's proposal with supporting documentation, followed by discovery and information exchange between parties. Public hearings provide opportunities for stakeholder input, while expert testimony and cross-examination help establish the factual record. After deliberation, the regulatory commission issues a final decision. These proceedings serve as the primary way for determining what costs are prudent and reasonable for recovery through customer rates, establishing the balance between utility financial health and consumer protection.

A key component of rate cases is the revenue requirement, which serves as the basis for determining rates charged to customers. The revenue requirement in COSR consists of several key components, as shown in Equation 2.1. Return on rate base provides utilities with the opportunity to earn their authorized rate of return on invested capital, while annual capital expenses include depreciation and amortization. Operating expenses include labor, materials, services, and fuel costs necessary to provide service. Various taxes, including income and property taxes, are also factored in, along with other approved costs such as demand-side management programs. The formula is often expressed as:

$$Revenue\ Requirement = Operating\ Expenses + (Rate\ Base * Rate\ of\ Return) \tag{2.1}$$

[2] Walter Adams. *The Role of Competition in the Regulated Industries*, 48 *American Economic Review* 527. 1958.

[3] While "rate case" is the commonly used term in the United States, the name of the process can differ in other jurisdictions. For example, rate cases are called rate determinations in Australia and price control review in the United Kingdom.

This comprehensive approach provides utilities with the opportunity to maintain financial viability while providing essential services.

COSR has several important implications for both utilities and consumers. A benefit of COSR is that it is designed to allow utilities to recover prudently incurred costs and provides a degree of regulatory certainty needed for capital-intensive investments. COSR also operates such that customers only pay rates for costs incurred prudently. However, COSR also has well-known limitations. The COSR model provides limited incentives for cost efficiency since cost increases can be recovered through rate cases that are timed, generally, at the discretion of the utility. If the utility has the ability to recover all prudently incurred costs whenever cost pressures challenge the ability to recover the allowed rate of return, the incentive to find cost efficiencies is reduced relative to an environment with limitations on timing rate cases. Furthermore, these regulatory proceedings can be resource intensive, which is especially costly in an inflationary environment, wherein utilities must file rate applications with greater frequency.

In most jurisdictions, utility management determines when to file rate applications. While rate case frequency varies considerably across regulatory landscapes, recent years have seen an uptick in filings nationwide, primarily driven by mounting capital investment needs and persistent inflationary pressures.[4] Recognizing the substantial administrative burden these proceedings place on both utilities and regulators, many jurisdictions have implemented limited adjustment mechanisms that allow for targeted cost recovery between comprehensive rate cases, creating a more flexible regulatory approach while maintaining appropriate oversight.

An alternative approach, commonly called either incentive regulation or PBR, aims to mitigate the shortcomings of traditional COSR by providing superior economic efficiency incentives and administrative savings. This alternative form of rate regulation has a decades-long history across multiple industries, including telecommunications, railroads, postal services, and oil transmission pipelines, as well as gas and electric distribution utilities.

## 2.2 Performance-Based Regulation (PBR)

In recent years, various forms of incentive regulation have increasingly drawn the attention of regulators and utilities as a potential means of improving electricity and gas utility efficiencies and reducing regulatory costs. One category of PBR tools, known as Multi-Year Rate Plans, set a predefined trajectory for rates over the course of the PBR rate term.[5] There are several variants of MYRPs. Indexed caps, in the form of either a price or revenue cap, work by limiting price or revenue growth to an inflation rate that is adjusted by a measure of industry productivity growth, thereby introducing competitive market pressures into a market that is largely considered to be dominated by non-competitive firms.[6] At the same time, the cap provides relief

[4] Lowrey, Dan. *Rate Requests by US Energy Utilities Set Record in 2023 for 3rd Straight Year. S&P Global Market Intelligence*. February 7, 2024.

[5] The PBR rate term is defined as the period of time the PBR plan is active. For instance, the term may last from 2025 to 2029, after which a rebasing period occurs in which rates are again aligned with the utility's cost of service, and a new PBR rate term may begin.

[6] In competitive markets, prices rise at the rate of inflation minus a productivity growth factor. This is often referred to as $I$-$X$ in incentive regulation, where $I$ is the rate of inflation and $X$ is a measure of productivity growth. Revenue growth is equal to price growth plus output growth, and so a cap on revenue growth in a

from earnings attrition over time by allowing rates to increase by a simple formula and is therefore sometimes called an attrition relief mechanism (ARM). In some cases, the indexed cap applies to a subset of total revenues, rather than the entire company's revenue requirement. Indexed cap plans that apply to a subset of total revenues are sometimes called "hybrid ARMs."

A second set of PBR tools, known as Performance Incentive Mechanisms (PIMs), provide incentives for utilities to produce certain outputs. Regulators may impose PIMs to encourage utilities to direct resources toward achieving certain goals that are not likely to be achieved under traditional regulatory frameworks. PIMs may be more easily added to existing utility remuneration models than indexed caps, as they do not require an overhaul of the entire framework, but instead could be as simple as a financial reward for achieving a performance target. The details of PIMs and indexed caps are explained in more detail in Sections 4 and 5.

Regulatory frameworks are not binary, which makes it difficult to draw a dividing line between "traditional" and "incentive" forms of regulation. PBR plans operate on a spectrum, often incorporating elements of traditional COSR in an attempt to both minimize business risks and maximize benefits to customers. Like an indexed cap that applies only to a subset of utility costs, regulatory frameworks that incorporate both elements of COSR and PBR more generally are sometimes called "hybrid" PBR plans.

Figure 2.1, depicts the spectrum of PBR along two dimensions: input efficiency and output efficiency. The figure shows that traditional cost-of-service regulation (COSR), in which costs and revenues are closely linked by annual rate application filings to set rates based on costs, provides limited input efficiency incentives. However, adding scorecard metrics or PIMs to a traditional COSR framework can strengthen the utility's output incentives. An indexed cap with no cost trackers tends to have the strongest input efficiency incentives. The introduction of PIMs tends to strengthen a framework's output efficiency incentives. Where a given regulatory framework in the real world exists on this spectrum cannot be pinpointed, but all utility regulation frameworks exhibit some level of efficiency along these two axes.

PBR plan may take the form *I-X+G,* where *G* is the growth rate in the utility's outputs. However, in many proceedings, utilities forego the *G* factor and its absence is treated as a customer dividend, or slower revenue growth which acts as a benefit to customers. These formulas are derived in Appendix B and explained throughout the report.

**Figure 2.1: Illustration of the Spectrum of PBR**

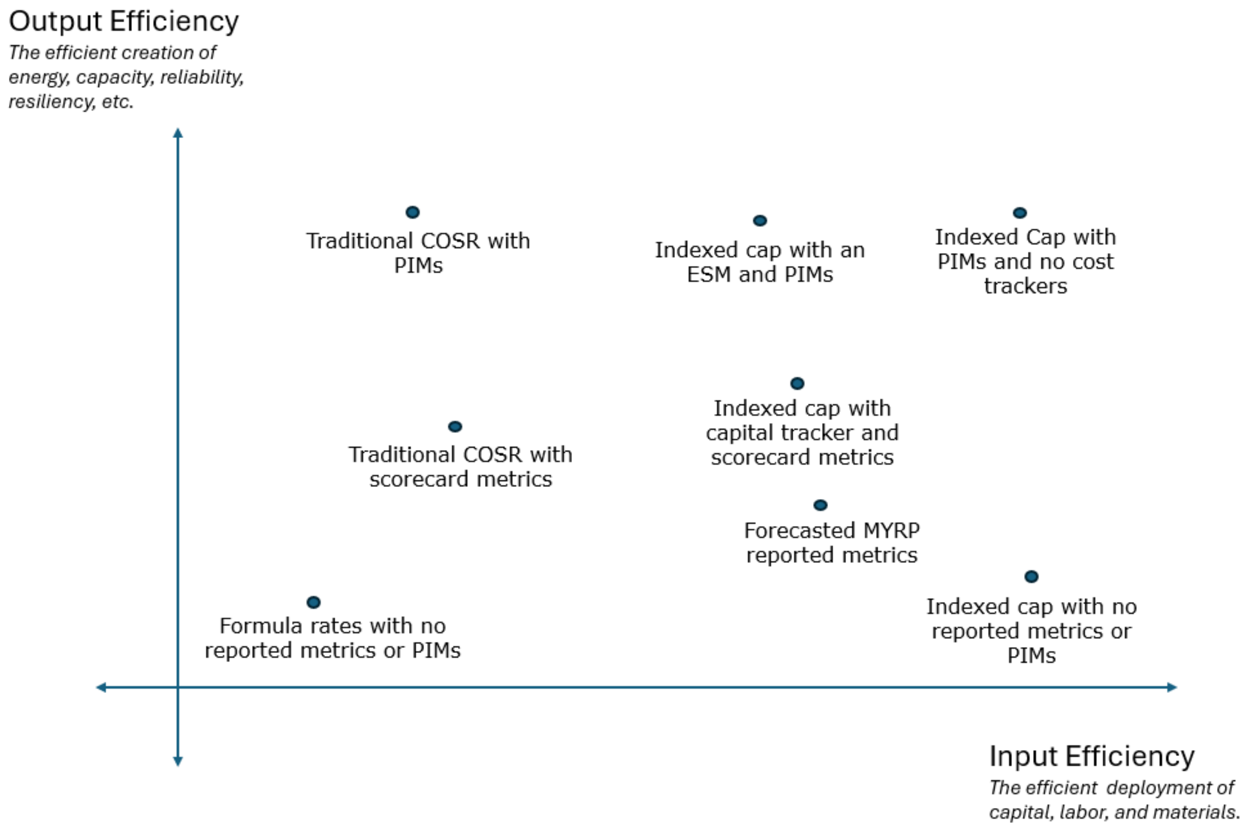



Figure 2.2 provides an overview of PBR development across the United States. PBR frameworks of some kind are also common abroad, in Canada, Europe, Australia, and New Zealand.[7] It includes information on states that are currently exploring or have previously explored PBR. Notably, the state of Maine already operates with elements of PBR, as Maine's existing service quality indicators have PBR incentives. A review of indexed cap (revenue and price cap) PBR plans in North America, Australia, and Great Britain reveals that PBR frameworks differ substantially across jurisdictions. For example, different jurisdictions approach revenue recovery of capital expenditures with different tools. While revenue recovery options for exogenous events are commonly included, the parameters that define them differ between utilities.

Since PBR terminology can vary across different jurisdictions, this figure may not capture every state that has implemented PBR mechanisms. Nevertheless, it serves as a helpful approximation of where PBR has been applied across various U.S. jurisdictions.

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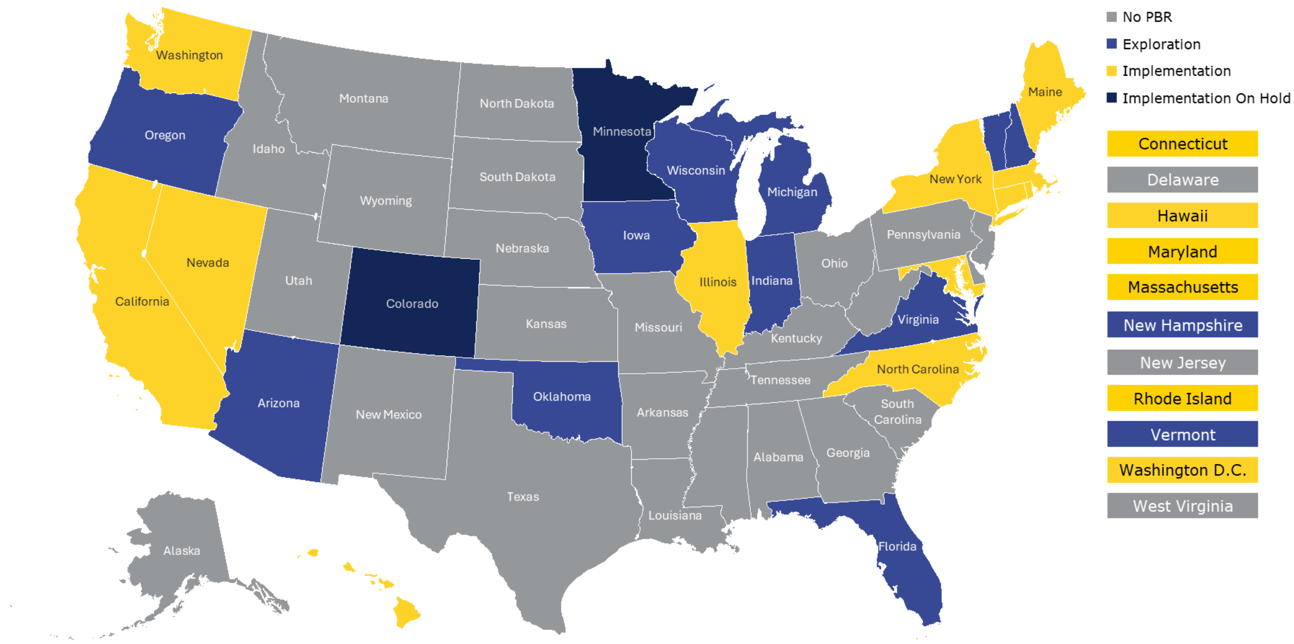
[7] Of the 35 European nations surveyed by the Council of European Energy Regulators, all but one regulated its distribution utilities with some form of incentive regulation. See "Regulatory Frameworks for European Energy Networks," Council of European Energy Regulators, February 3, 2025.

**Figure 2.2: Status of PBR Across United States**[8]

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[8] Data for this figure from "Tracking State Developments of Performance-Based Regulation," by National Association of Regulatory Utility Commissioners, April 2024. It has been modified to include other PBR developments CA Energy Consulting is currently aware of.

# 3 FUNDAMENTALS OF PERFORMANCE-BASED REGULATION

## 3.1 Introduction to PBR

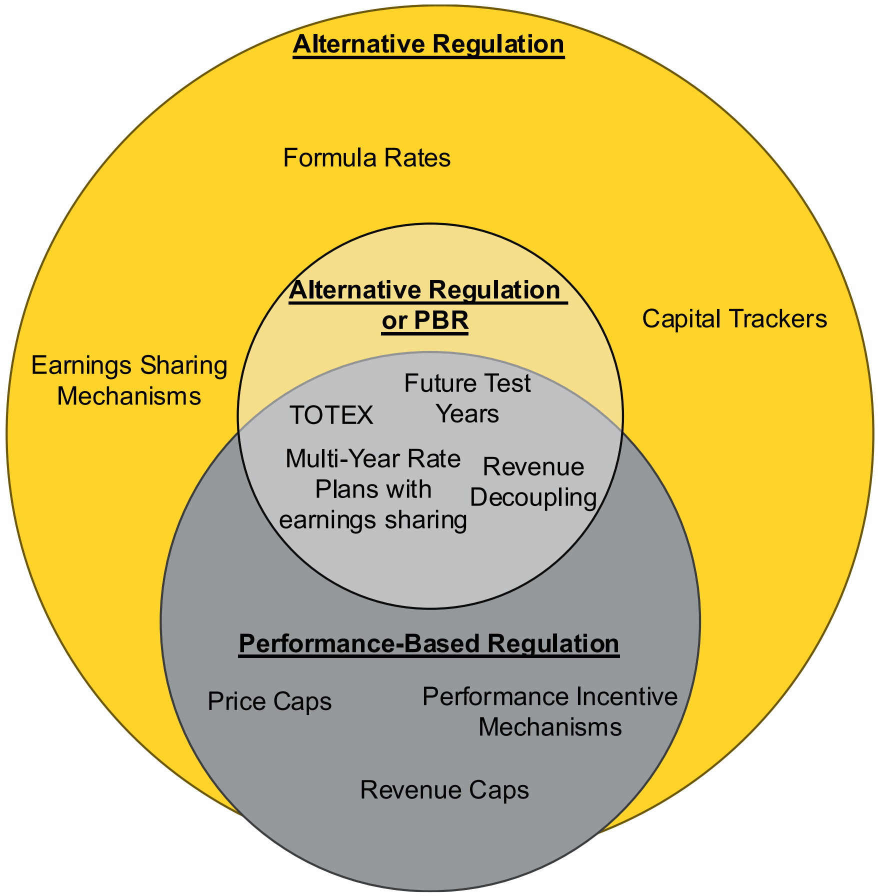
Performance-based regulation is an approach to regulating utilities that emphasizes the achievement of outcomes that benefit ratepayers and utilities through the use of financial incentives. PBR tools may create incentives for cost efficiency, a reduced regulatory burden, enhanced service quality, or the achievement of any number of policy objectives. The principal goal of PBR is to correct for the limitations of traditional regulation and align utility incentives with broader societal goals, such as improving service reliability, promoting affordability, and reducing environmental impact.

As discussed in Section 2.2, PBR can be challenging to define, as it is an umbrella term that refers to a suite of tools that lie along a spectrum of incentive power. The two primary groups of PBR tools are Multi-Year Rate Plans (MYRPs) and PIMs. In general, MYRPs are focused on input efficiency: the aim is to incentivize the utility to produce its outputs using the least-cost combination of inputs like capital, labor, and materials. PIMs, on the other hand, focus on outputs. In an era of energy transition, PIMs may assist with promoting the production of outputs not traditionally required of utilities (for example, DER connections, Electric Vehicle (EV) charging stations, and so-called "non-wires solutions"). These two sets of tools can be used together.

Defining a particular regulatory paradigm as "PBR" is complicated by the details of each regulatory framework. Some long-standing regulatory frameworks already incorporate elements of PBR, even if not explicitly identified as such. For example, service quality indicators like SAIFI and CAIDI in Maine, which include penalties for failing to meet predetermined thresholds, could fit the definition of a PBR tool – in this case, PIMs. The industry acknowledges that PBR is not a binary term, and also that tools that are considered "alternative" to traditional regulation do not necessarily provide enhanced efficiency incentives to utilities.

Figure 3.1 depicts the classification of various alternative regulation tools, which will be defined and discussed in the remainder of this section. The figure shows that some alternative regulation mechanisms, like formula rates, Earnings Sharing Mechanisms (ESMs), and capital trackers are not PBR tools. While the primary PBR tools can generally be placed within the categories of either MYRPs or PIMs, there is a gray area including examples like an MYRP with an ESM, which may have lower-powered incentive properties relative to a price or revenue cap.

**Figure 3.1: Categorizing the Tools of PBR**




Broadly speaking, when PBR tools are paired with traditional forms of cost-based regulation, financial risk is reduced, but so are the utility's performance incentives. The preferred balance of risk and incentives will depend on the jurisdiction. Likewise, the feasibility of implementing PBR tools, as well as the expected outcomes, will vary by utility. As such, different jurisdictions have implemented PBR in different ways, tailoring their approach to the unique goals and priorities of the utility, the local industry structure, and the policy goals of the jurisdiction.

Subsequent sections of this report provide a discussion of PBR tools currently used in North America. We define terms, discuss benefits and drawbacks, delve into practical applications, and examine how each tool functions within a utility's regulatory framework.

## 3.2 Guiding Principles of PBR

The design of a regulatory framework should be based on sound economic and public policy principles. Regulators in jurisdictions that have adopted PBR often articulate principles specific to incentive regulation in order to establish a basis for the design and operation of PBR plans. Utilities may rely on these principles when planning rate applications. Stakeholders may want to assess proposed frameworks using these same principles.

If the state of Maine decides to pursue PBR for its electric utilities, we recommend soliciting stakeholder feedback regarding the following principles, which are based on decisions by the

Alberta Utilities Commission[9] and the British Columbia Utilities Commission.[10] These principles are specific to the development of PBR frameworks, and do not supersede or negate other guiding regulatory principles (e.g., the so-called "Bonbright Principles").

> Principle 1: The PBR plan should, to the greatest extent possible, create similar efficiency incentives compared to those experienced in a competitive market while maintaining service quality.
>
> Principle 2: The PBR plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> Principle 3: The PBR plan should recognize the unique circumstances of the company that are relevant to the PBR design.
>
> Principle 4: Customers and the regulated companies should share the benefits of a PBR plan.
>
> Principle 5: The PBR plan should be easy to understand, implement, and administer and should reduce the regulatory burden over time.

Reaching a consensus on the objectives and design of a PBR plan among industry stakeholders requires time and communication. While the principles above can be considered a useful starting point, industry conditions and preferences in Maine may differ from those in Canada. We encourage stakeholders to provide feedback on this initial recommendation, such that a consensus may be reached. We provide in Appendix C the original list of guiding principles from Alberta and British Columbia, as well as principles from Ontario, Massachusetts, and Hawaii.

Table 3.1 contains a summary of our recommendations regarding guiding principles of PBR for the state of Maine. We find that the seven regulatory goals set forth in the Maine legislature's draft language provide an adequate basis for evaluating regulatory frameworks in Maine.

**Table 3.1: Recommendations for Guiding Principles of PBR**

| | |
|---|---|
| Guiding Principles of PBR | *The seven regulatory goals set forth in Section 7.3 stem from the draft legislative language that prompted this investigation. These goals provide an adequate basis for evaluating the regulatory frameworks applied to Maine IOUs, PBR or otherwise.* |

[9] Alberta Utilities Commission. *Decision 2012-237*. September 12, 2012. p. 7.

[10] British Columbia Utilities Commission. *Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024*, *Decision and Orders G-165-20 and G-166-20*, June 22, 2020. p. 168.

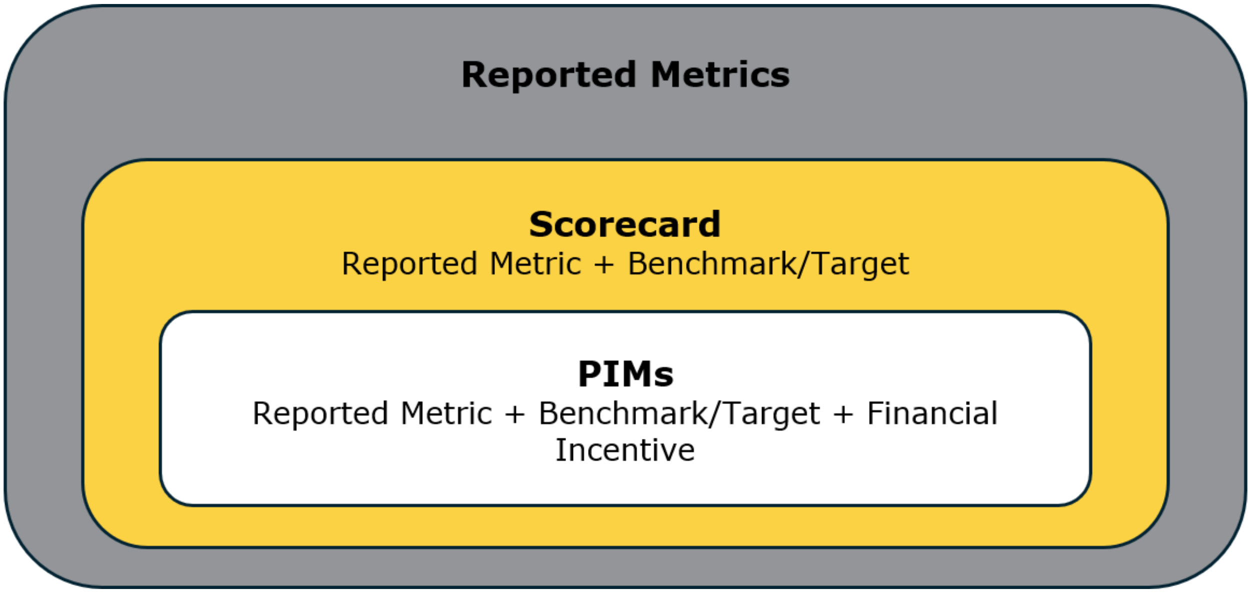
# 4 PERFORMANCE INCENTIVE MECHANISMS (PIMS)

Performance Incentive Mechanisms (PIMs) constitute the category of PBR tools focused on incentivizing certain utility outputs. These mechanisms are designed to align utility performance with regulatory and public policy goals by providing financial incentives for achieving specific performance targets. PIMs are distinct tools from "reported metrics" and "scorecard metrics," which do not employ financial incentives. Our conclusion is that Maine's regulated utilities currently operate under a set of PIMs (see Section 7.2).

Most utilities publish metrics aimed at providing information on service quality. Utilities, regulators, and other stakeholders benefit from these metrics. Utilities can use performance metrics to better understand areas where improvement or investment is needed. Regulators and other stakeholders benefit through increased transparency into the health of the utility, which can help with establishing policy. The regulator may also better understand certain revenue needs outlined in the utility's rate application if it has insight into the utility's performance history. Deteriorating performance in particular categories might warrant enhanced investment. For customers, scorecards can contextualize the service they receive as individuals within the broader system, which can help with developing sensible consumer advocacy and expectations. These metrics provide a common assessment point between all parties when evaluating utility performance.

As depicted in Figure 4.1, scorecard metrics add a layer of accountability to reported metrics by introducing benchmarks or targets. Establishing such benchmarks can assist with evaluating whether the utility meets its expected service quality. However, scorecard metrics do not involve financial rewards or penalties. PIMs differ from reported metrics and scorecards in the use of financial incentives. For each performance area, regulators establish specific metrics, performance targets, and a system of rewards and penalties. When utilities exceed the established targets, they may earn additional revenue. Conversely, if they fail to meet the targets, they may face financial penalties or reduced returns. Whether a PIM administers penalties or rewards—or both—depends on the design of the PIM.

**Figure 4.1: The Hierarchy of Reported Metrics, Scorecards, and PIMs**[11]




The subject of performance metrics often arises in discussions of indexed cap or forecasted MYRP frameworks because of a theoretical possibility that the cost-cutting incentives of revenue or price caps will lead to service quality degradation. Metrics can provide counter-pressure to the incentive to cut costs during a PBR stay-out period by providing incentives to maintain superior performance. A performance metric may be focused on preventing poor performance.[12] Although a review of industry literature does not indicate any link between PBR incentives and reduced service quality, performance metrics are seen as a mechanism for monitoring the quality of utility service at the same time that the company faces cost-related efficiency incentives.

## 4.1 Definition of PIMs

A PIM is an annual revenue adjustment mechanism that ties financial incentives to the achievement of pre-defined benchmarks or targets. PIMs can be reward-only, penalty-only, or symmetric, meaning they could result in both a reward and a penalty. Typically, PIMs operate by adjusting a utility's ROE, though in some cases a pre-determined dollar value is used for a penalty or reward.

To be considered a PIM, the utility must have a measurable target, and it must be possible to recognize the achievement of this target using publicly available information at the end of each year when rates are set for the subsequent year of the PBR term. In addition, the financial penalty or reward associated with achievement of (or failure to achieve) the target must be known in advance. PIM penalties or rewards will be applied to rates each year as a rider, adjusting revenues according to performance in the most recent completed year.

[11] This figure was adapted from: Decision and Order 37507. Hawaii Public Utilities Commission. Docket No. 2018-0088. p. 155.
[12] Whited. *Utility PIMS – A Handbook*. 2015. p. 16.

The Service Quality Indicators (SQIs) currently in place for Maine's utilities are PIMs in all but name. They have a clear performance target that the utilities must maintain and failure to maintain these performance targets results in penalties.

## 4.2 Considerations for Designing PIMs

A clear set of criteria for the development of PIMs has not been widely adopted across jurisdictions that operate under PBR. However, several jurisdictions have developed principles and guidelines for PIM design. For example, the New York Public Service Commission (NYPSC) offered a useful direction that PIMs should accomplish one of two objectives: (1) encourage achievement of new policy objectives or (2) counter implicit negative incentives that the state's ratemaking model provides.[13]

One question about the design of PIMs is whether to make the financial incentive a reward, a penalty, or financially symmetric — meaning that the PIM offers a reward for positive achievement and a penalty of sub-par achievement. One approach to answering this question is to offer a reward if the utility has not been expected to produce the output in the past, since the cost is not reflected in rates, and a penalty if the utility is expected to provide the output. For example, if a certain level of reliability is expected, a SAIDI or SAIFI PIM could be penalty-only. For new policy objectives, like faster home connections or Non-Wires Solutions, achievement could be tied to reward-only PIMs.

Additional criteria for designing a new PIM may include:

- Does not cause a large increase in administrative burden for utilities, stakeholders, or the regulator;
- Where outcomes align, uses/builds on existing data measured by Maine IOUs;
- Are consistent with/takes into consideration other initiatives on-going in Maine, including existing PIMs;
- Tracks outcomes that utilities can control;
- Have rewards and penalties that are proportionate to the value provided by the achievement of a PIM target (accounting for costs of administering a PIM);
- Are unambiguous, easily interpreted, and objectively verifiable;
- Address policy goals or priorities that are not adequately addressed in existing regulation tools/policies;
- Provide benefits to ratepayers.

These proposed criteria are in line with PIM design principles and guidelines in other jurisdictions such as Rhode Island, Massachusetts and D.C.[14] PIMs need to be evaluated holistically to ensure the metrics do not work at cross purposes with each other.

[13] Interestingly, the NYPSC rejected arguments that PIMs should be restricted to items under the utility's direct control or strong influence, stating that an outcome-oriented approach was the most effective route.
[14] Goldenberg et al. *PIMs for Progress: Using Performance Incentive Mechanisms to Accelerate Progress on Energy Policy Goals, Rocky Mountain Institute*. p72-75.

**PIMs Proposed by National Grid in Rhode Island**[15]

In 2018, the Public Utilities Commission of Rhode Island did not accept six out of seven PIMs proposed by Narragansett Electric Company d/b/a National Grid. The Commission evaluated National Grid's PIMs using the following eleven questions:

1. Does the incentive promote the realization of new consumer and societal benefits?
2. Does the incentive promote behavior that the utility otherwise would not take?
3. Is there a clear nexus between the metric and the expected benefits?
4. Is there a clear, stated reason why the incentive is needed to achieve each specific objective?
5. Is the incentive designed to promote superior utility performance and significantly advance the expected benefits as efficiently as possible?
6. Is the incentive designed so that customers receive most of the benefit?
7. Is the incentive designed to grant increasing levels of rewards to the utility for higher levels of performance?
8. Will the design and implementation of the incentive be completely transparent and fully document and reveal inputs and methodologies to ensure no duplication of incentives across various ratepayer funded programs?
9. Is it possible to compare the cost of achieving the metric to the potential benefits?
10. What objectives does this incentive promote?
11. Are these opportunities for the company to earn multiple incentives for attaining the same objective?

For example, the commission rejected the PIM on "$CO_2$ Electric Vehicle PIM," as the company may already propose a performance incentive that rewards emission reductions within the existing energy efficiency program plan (see Question 2). All six rejected PIMs were approved as track-only metrics with no financial incentive attached.

A question regarding the adoption of PIMs in the state of Maine is whether new PIMs might be imposed on the IOUs, or whether the IOUs may propose their own individual PIMs through a regulatory proceeding. A regulator might impose a standard set of PIMs on utilities in order to achieve a policy objective that utilities might not pursue voluntarily. The drawback, however, is that the same PIM may affect different utilities in different ways. One utility may face conditions that make achievement of certain benchmarks easier than for a utility operating under different conditions. Certain PIMs may cause a proportionally larger administrative burden for small utilities compared to large utilities. Stakeholder engagement can help with evaluating whether a new PIM could be reasonably applied to all utilities in Maine.

Notably, PIMs generally do not aim to address overall utility cost efficiency. This is because PIMs are primarily concerned with the production of utility *outputs*. MYRPs like indexed caps confront the matter of efficient inputs and are therefore better suited for addressing cost efficiency.

[15] Rhode Island Public Utilities Commission. *Report and Order No. 23823 issued to National Grid and the Parties accepting the Amended Settlement Agreement*. p30.

## 4.3 Challenges to the Implementation of PIMs

There are several issues with providing financial incentives to utilities on the basis of performance metrics. First, utilities operate in a complex macroeconomy which can provoke service quality shocks exogenous to management's control. Penalizing a utility for failing to meet targets due to uncontrollable factors, through a PIM, can render the regulatory framework's incentives ineffective. It is also likely that stakeholders would protest paying financial reward to a utility for achieving goals merely through chance. Policymakers should take care to set PIMs on the basis of metrics that are reasonably within the control of the utility.

**Proposed Exclusions from a Reliability PIM**

As an example of a PIM design that has attempted to reflect controllable performance, consider the following reliability PIM. This PIM includes six qualifiers to System Average Interruption Duration Index (SAIDI).

In 2024, Public Service Company of New Hampshire d/b/a Eversource, an electric distribution utility in New England, proposed a penalty-only reliability PIM based on SAIDI for its electric operations. For the purpose of calculating a financial penalty for this PIM, Eversource proposed to adjust its SAIDI measure for the following items:

1. Interruptions that are resolved within 5 minutes or less;
2. Private customer outages;
3. Planned outages;
4. Loss of external supply;
5. Public safety directed outages;
6. Major event days.

These adjustments assist with focusing the PIM penalty on reliability shortfalls within the control of management.

Second, incentive pressure from PIMs may operate with a lag, as management learns how to better find efficiencies or as new investments take time to provide intended benefits. For this reason, some metrics may have limited ability to capture management performance efforts. For example, plant additions aimed at improving reliability may take over a year to implement—and thus, a utility may face penalties even after making system upgrades aimed at avoiding such penalties. In such cases, measures observed over longer time horizons may be more suitable.

Third, obtaining reliable performance metrics for the desired outcomes may be challenging. When designing a PIM, a utility's performance on desired outcome needs to be translated to measurable metrics. These metrics should be based on reliable and consistent data. For example, if the metric wants to measure customer satisfaction with a particular service the utility provides, surveys may need to be designed and implemented. The design of survey questions, sampling methodology, and/or sample size are all important factors to ensure the results actually reflect customer satisfaction. The data collection method should be consistent across years to support accurate comparisons. When multiple potential metrics are available for the same outcome, identifying the best metric may require careful analysis, testing, and refinement.

Fourth, performance metrics have costs. As discussed in the previous paragraph, data gathering may involve considerable time and work. Poorly designed metrics may have large data requirements that are not easily fulfilled, leading to inefficiencies and costs that outweigh the benefit of the information they might provide. One of the costs of establishing performance metrics is determining the appropriate thresholds above or below which a utility will be rewarded or penalized, as well as the magnitude of the reward. This may require expert evaluation, and even with such expert evaluation, a fifth challenge is that the proper amount of reward or penalty will likely be an estimate. Measurement error can result in imbalanced or unfair PIMs.

A sixth consideration in the creation of performance metrics is the concept of "single issue regulation." A metric may obfuscate a problem if it misrepresents the intended goal of the metric, or it may give rise to unintended consequences as the utility optimizes to maximize earnings. For example, if a utility creates a single metric to measure customer service quality by recording the average number of minutes a customer waits on the phone, on hold, the company may become very good at answering calls quickly but neglect other avenues of customer communication like website interaction. A crucial point in the construction of a service quality measurement plan is that the scorecard should consider individual elements as well as the mission as a whole. If the utility focuses on each metric in isolation, some metrics may result in competing incentives. On the other hand, too many metrics can lead to a higher regulatory burden that counteracts the PBR framework's efficiency goals.

Whether or not the utility operates under PBR, management and regulators must balance the costs and benefits of performance metrics, lest the utility suffer from an excessive number of goals, or a set of goals that place excessive pressure on the company's operations. Table 4.1 provides an overview of advantages and challenges of PIMs.

**Table 4.1: Advantages and Challenges of Performance Incentive Mechanisms**

| ADVANTAGES | CHALLENGES |
| --- | --- |
| **Alignment with Public Policy Goals**<br>• Facilitates the promotion of prioritized policy goals.<br>• Shifts the focus from capital investment to measurable outcomes. | **Design Complexity**<br>• Present challenges regarding the quantification of performance outcomes and set appropriate rewards/penalties.<br>• Requires the development of measurable, timely metrics. |
| **Improvements in efficiency**<br>• Provides incentives to achieve specific performance goals.<br>• Protects against service quality declines while considering economic efficiency. | **Accounting for External Factors**<br>• May not fully account for uncontrollable external factors.<br>• May require more complicated data interpretation that detracts from administrative simplicity. |
| **Flexibility and Transparency**<br>• Increases transparency in utility performance through measurable metrics.<br>• Have flexibility to adjust to changing market conditions | **Unintended Consequences**<br>• Can lead to attention toward specific goals to the detriment of service that is not rewarded/penalized.<br>• May create risk of gaming or manipulation by utilities. |

## 4.4 How to Set Reward and Penalty Targets

A PIM administers a reward (or penalty) to the utility for the achievement of (or failure to achieve) certain pre-determined targets. The determination of these targets should be based on economic principles and data. There are three general categories of methods for setting targets: (1) based on the utility's own past performance; (2) based on the utility's performance in comparison to its peers; and (3) based on quotas or levels set by policy. Whether to use a particular one of these methods depends on the type of PIM, data availability, and the details of the policy objectives the PIM aims to address.

Currently, PIMs in Maine are penalty-only. However, PIMs that offer a financial reward could be considered as tools to address new policy objectives, or to incent activities that are not traditional expectations of electric distribution utilities.

### *4.4.1 Thresholds Based on Utility's Own Past Performance*

A utility's own past performance has been used to set PIM benchmarks in other jurisdictions.[16] A utility may set a baseline using average historical performance, perhaps over five or ten years of history. In choosing the measurement period of historical performance, there is a trade-off: a

[16] See, for example, Hawaii.

longer historical time period can help to smooth over noise in the data that may be outside of the utility's control, but older data may not reflect recent performance and changes in the utility's policy environment. A threshold might then be set equal to one or two standard deviations from this average. A threshold set according to mean and variance information assumes that past performance reflects a reasonable range of performance in the future. It also assumes that a penalty or reward is warranted when performance deviates sufficiently from historical average performance. Other adjustments like weather normalization may be applied to the historical average.

One reason for using a utility's own past performance is that cross-company comparisons may not accurately reflect its unique operating conditions. Different utilities operate in different physical environments, are at different stages of their capital cycle, have different systems, and serve different customer mixes. All of these factors may affect the utility's performance relative to its peers. Applying rewards or penalties on the basis of factors like these, which are beyond the control of company management, may not be just and reasonable.

Another advantage of the historical performance approach is it is relatively simple. In contrast, when comparing companies, the PIM threshold may require a regression model or some other means of controlling for factors driving differences between firms. This introduces the possibility of disagreements regarding technical design, as well as data requirements that could be burdensome. Simple historical averages mitigate this problem.

However, using the utility's own data in setting performance thresholds controls for some factors, but not all. Past performance may differ from the future as a result of system changes, even within the same utility. For example, system upgrades might improve reliability and reduce the standard deviation of reliability measures. Conversely, changing climate conditions may reduce reliability relative to the past. Furthermore, if the utility has not collected the necessary data prior to the introduction of the PIM, the company will need to expend resources to introduce new data collection systems.

Another possible shortfall of this approach is that a utility's past performance may be better or worse than peer companies for reasons within management's control, and as a result, this method could set penalty or reward threshold levels above or below what is reasonable. For example, if a utility works hard to maintain a high level of reliability over time, and then a SAIDI PIM is imposed, it may be punished for good historical performance in the form of challenging threshold levels. Similarly, if the utility knows that future PIM thresholds will be based on current performance, management has some ability to manage SAIDI levels for future benefits. In other words, the PIM becomes *endogenous* to company performance, rather than *exogenous.*

### *4.4.2 Thresholds Based on Comparison to Peers*

Setting PIM thresholds in relation to peer companies involves comparing a utility's performance on specific metrics with the average performance of similarly situated peer utilities. For example, a threshold may be set based on the current year's industry average and standard deviation values, rather than the utility's own historical average.

There are several advantages to making comparisons across peer companies. First, thresholds based on cross-sectional peer performance reflect current conditions and the experience of customers served by utilities regionally. Peer-based thresholds may be more relevant because of the use of contemporaneous data, rather than data from five or ten years in the past. Second, if the goal is to provide similar service quality for all customers, regardless of utility-specific conditions, the peer benchmarking approach is a more relevant measure. Third, whereas utility-specific thresholds may involve some endogeneity, peer-based thresholds are strictly exogenous. This means that a utility that performs well over time relative to its peers is not punished for its good performance.

Drawbacks to the peer benchmarking approach include increased complexity and the possibility that benchmarks are not set relative to a utility's operating conditions. Performance benchmarking across utilities requires more data and the use of more technical methods, increasing the complexity and potential administrative burden of the approach.

### *4.4.3 Thresholds Based on Quotas or Policy*

In some cases, industry standards may set PIM thresholds irrespective of utility historical data or sector-wide cross-sectional data. For example, if a regulator has established a goal of connecting new DER customers within a certain number of days, a utility's past performance, or the performance of its peers in making these connections, may not be relevant. In such cases, the regulator may consider data to frame the threshold, even if the data is not explicitly used to calculate a specific threshold value.

This approach may be used because of data limitations. It may also be the case that the regulator deems empirical information less relevant for the purposes of determining thresholds, as the goal is to achieve a set threshold regardless of current or past utility performance. A drawback, however, is that stakeholders may dispute thresholds not based on concrete data.

## 4.5 Summary of PIMs Concepts

Utility outputs span more dimensions than just kilowatt-hours of electricity. Output dimensions also include reliability, safety, system efficiency (i.e., load factor), connection time, and customer service. Increasingly, outputs also may involve addressing environmental policy goals like DER connections, the incorporation of EV charging stations, and energy efficiency. Utilities may not have a natural incentive to prioritize certain non-traditional outputs, or perhaps stakeholders agree that enhanced attention to traditional outputs is required. PIMs can offer an economically efficient means to achieving objectives or remedying deficiencies by attaching financial incentives to the achievement of pre-defined standards.

Generally, regulators and utilities institute PIMs after identifying specific, targeted policy goals related to utility outputs. This involves establishing metrics, defining achievement thresholds, and setting financial rewards or penalties. The implementation of PIMs requires careful design to ensure they effectively drive desired outcomes without unintended consequences. Key considerations include selecting metrics that are meaningful, measurable, and within the utility's control; setting challenging but achievable targets; and determining the magnitude of financial incentives that will motivate utilities without unduly burdening ratepayers. We have provided criteria in Section 4.2 that can guide the development of successful PIMs.

Whereas transitioning from a traditional form of cost-of-service regulation to an indexed cap may entail substantial changes for the utility, stakeholders, and the regulator, PIMs have the advantage of being relatively compatible with existing utility remuneration frameworks. For example, a company could add a DER connection PIM to its existing framework, change nothing else, and continue its operations with a new performance-based incentive aimed at achieving a policy goal.

The MPUC and the state's IOUs have established a foundation through existing reliability and customer service PIMs (SQIs), which encourage utilities to maintain service standards. Building on this experience, Maine could expand beyond the current SQIs, using PIMs to advance additional policy priorities and innovation. We recommend that the MPUC, the regulated utilities, and stakeholders collaborate to prioritize policy goals that are currently unaddressed by the state's regulatory framework and establish metrics that reflect the achievement of these goals.

**Table 4.2: Recommendations for PIMs in Maine**

| | |
|---|---|
| Recommendations for PIMs in Maine | *1. We recommend that the Maine PUC allow the state's IOUs to file new PIMs as part of future rate applications, to be assessed on a case-by-case basis. We recommend using the guidelines provided in Section 4.2 in the design of these PIMs.*<br><br>*2. We recommend that before instituting any mandatory PIMs or any PIMs that apply to all IOUs, the Maine PUC determine which specific policy goals might be addressed by PIMs and meet with stakeholders to discuss potential benefits and drawbacks of attaching financial incentives to related metrics. We recommend following the criteria set out in Section 4.2 prior to implementing mandatory PIMs.* |

## 4.6 PIMs in Practice

PIMs have played a role in the United States utility sector since the late 1980s, with use in Maine dating back to the 1990s in the form of Service Quality Indicators (SQIs).[17] PIMs in the US were initially designed to provide financial incentives for utilities to invest in energy efficiency programs. In recent years, these tools have gained increased attention for their potential to support state carbon neutrality goals, as well as to enhance system reliability, improve customer service responsiveness, expand outreach initiatives, facilitate the deployment of distributed energy resources (DERs), and promote non-wire alternatives over traditional capital investments, among other objectives.

The history of PIMs in the United States is closely linked to broader shifts in regulatory practices, particularly in the electric utility industry. The introduction of the Public Utility Regulatory Policy Act of 1978 (PURPA) and the Energy Policy Act of 1992 were pivotal, fostering the development of independent power generation.[18] These changes led to the restructuring of utilities with states separating integrated utilities into distinct generation and transmission and distribution entities,

[17] Maine Public Utilities Commission. *Docket No. 2022-0152*. January 20, 2023.

[18] Joskow, Paul L. *The Expansion of Incentive (Performance-Based) Regulation of Electricity Distribution and Transmission in the United States. Review of Industrial Organization* 65.2. 2024. p. 455-503.

allowing independent power providers to operate alongside the existing grid. This shift in regulatory structure set the stage for mechanisms to incentivize utility performance outside of power production.

In recent decades, the responsibility of electric utilities has expanded, particularly with the growing emphasis on reducing carbon emissions. The introduction of PIMs was a response to this evolving landscape, aiming to motivate utilities to achieve goals they might not pursue without external incentives. Initially, PIMs were primary implemented in lines-only utilities, but over time their use has spread to integrated utilities.[19] A notable example is Hawaii where multiple PIMs have been established as part of the state's adoption of a comprehensive PBR framework in 2021.

A key challenge in discussing PIMs across jurisdictions lies in the variety of terms used to describe similar concepts. While the underlying principles of PIMs remain consistent, they may be referred to by different names depending on the jurisdiction. A good example is Maine's SQIs, which function as PIMs in all but name. These indicators measure outcomes such as System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI), and include a prescribed incentive – specifically, a financial penalty for failing to meet predetermined goals. Maine is not alone in using different terminology; SQIs are a common form of PIM, though not always referred to as such. Other examples of PIM terminology differences include New York's Earning Adjustment Mechanisms (EAMs) and Great Britain's Optimization Output Delivery Incentives (ODIs).

Outside of the United States, PIMs have been implemented by all other major English-speaking countries, each adapting the concept to fit their regulatory frameworks and policy goals. These countries include the United Kingdom, Ireland, Australia, New Zealand, and Canada.

Within the United States, the RMI PIM database offers a record of PIMs implemented over the past several years.[20] CA Energy Consulting leveraged this data to identify PIMs related to four key areas of interest for based on Maine's policy objectives: Interconnection, Greenhouse Gas Emissions, Smart Meters, and Affordability and Cost Control. For each category, we further classify the PIMs into three groups: those that are applicable to Maine ("Yes"), those that are applicable in theory ("Maybe"), and those that are not applicable ("No"). A PIM was classified as "Maybe" if it applies to a specific program for that utility that may not exist in Maine, if some aspects are relevant only to vertically integrated utilities, or if it is only tangentially related to Maine's interests. PIMs were classified as "No" if Maine already has a similar PIM, if the PIM is specific to vertically integrated utilities, or if other criteria prevent it from being applicable to Maine. Beyond applicability, we categorize the PIMs based on their incentive structures: penalty-only, symmetrical, or reward-only. The number of PIMs in each group is illustrated in Table 4.3 below.

[19] National Conference of State Legislatures. *Performance-Based Regulation: Harmonizing Electric Utility Priorities and State Policy.*

[20] [RMI PIMs Database]

**Table 4.3: RMI PIMs Database**

| PIM Category | Applicability to Maine | Transmission and Distribution | | | Vertically Integrated | | |
|---|---|---|---|---|---|---|---|
| | | Penalty Only | Symmetrical | Reward only | Penalty Only | Symmetrical | Reward only |
| Inter-connection | Yes | - | 2 | 17 | - | 1 | 3 |
| | Maybe | - | - | 6 | 1 | 1 | 1 |
| | No | - | - | - | - | 1 | 2 |
| Greenhouse Gas Emissions | Yes | - | 3 | 18 | - | - | 3 |
| | Maybe | - | - | 9 | - | - | 5 |
| | No | - | - | - | - | 1 | 2 |
| Smart Meters | Yes | - | - | 2 | - | - | 1 |
| | Maybe | - | - | - | - | - | - |
| | No | - | - | - | - | - | - |
| Affordability and Cost Control | Yes | - | 2 | 23 | - | - | 3 |
| | Maybe | - | 14 | 14 | - | - | 3 |
| | No | - | - | - | - | 23 | 7 |
| Not Relevant | - | - | 12 | 16 | 4 | 2 | - |

The table above shows that the majority of PIMs in RMI's database are either reward-only (66.8%) or symmetrical (30.7%). While this finding is helpful, readers should take some caution that RMI's database may not be comprehensive. As discussed earlier, many SQIs function as PIMs in practice but are not labeled as such, which could lead to their exclusion from databases like this. Nevertheless, the database indicates a preference for some form of upside incentives.

In the following subsections, we further explore PIMs by looking at examples in three states: Illinois, New York, and Hawaii. Each state provides examples of various PIMs that are pertinent to Maine, highlighting different approaches across transmission and distribution utilities (Illinois and New York) and integrated utilities (Hawaii).

### *4.6.1 PIM Example: Illinois*

The state of Illinois offers an example of a jurisdiction where lines-only utilities operate under PIMs that align with Maine's stated policy objectives. For example, Ameren Illinois Company (Ameren) has a demand response PIM, which aims to reduce greenhouse gas emissions, as well as an interconnection timeliness PIM applicable to DER customers.

PIMs have been employed in Illinois since the early 2010s, following the introduction of the Public Act 97-0616 in 2011, otherwise known as the Energy Infrastructure Modernization Act, which mandated PBR in the state.[21] The use of PIMs was further explored and expanded with the enactment of Public Act 102-0062 in 2021.[22] This Act provided the regulatory framework under which PIMs currently operate. As a result, both Ameren and Commonwealth Edison implemented

[21] Tabish, Herman. *Performance-based regulation: Seeking the new utility business model. Utility Drive.* July 23, 2019.
[22] NARUC. *PBR State Working Group. Tracking State Developments of Performance-Based Regulation.* January 2024.

PIMs as a part of their most recent rate plans.[23] A detailed examination of the subset of Ameren's PIMs that may be worth consideration by the MPUC are provided in the table below. Note that the listed PIMs are not comprehensive, as Ameren has additional PIMs, including reliability metrics similar to Maine's SQIs.[24]

**Table 4.4: Selected PIMs in Illinois[24]**

| Category | Example | Details of approved EAMs |
|---|---|---|
| **Greenhouse Gas Emissions** | Peak Load Reduction (2022) | Incents peak load reduction from a demand response program.<br><br>Metric: MW of peak load reduction.<br><br>Incentive Structure: Symmetrical<br><br>Reward: If peak load reduction exceeds 25 MWs relative to a baseline Ameren can start receiving rewards. The maximum reward is +3 basis points with a 50+ MW reduction.<br><br>Penalty: If peak load is less than 20 MWs relative to a baseline Ameren can start receiving penalties. The maximum penalty is -3 basis points with a 0 or less MW reduction.<br><br>Status: Active |
| **Affordability and Cost Control** | Affordable Customer Delivery Service Costs (2022) | Incents Ameren to introduce proactive measures to decrease arrearages.<br><br>Metric: Residential disconnections from non-payments in areas of Ameren's service territory with historically high disconnection rates.<br><br>Incentive Structure: Symmetrical<br><br>Reward: +3 basis points if target is met<br><br>Penalty: -3 basis points if target is not met<br><br>Status: Active |
| **Interconnection** | Interconnection (2022) | Incents Ameren to reduce the number of days it takes to interconnect customer DERs.<br><br>Metric: An interconnection index which is based on the number of days saved in the DER interconnection process.<br><br>Incentive Structure: Symmetrical<br><br>Reward: +1.5 basis points if the value is between the performance target and 1.25. +3 basis points if greater than 1.25.<br><br>Penalty: -1.5 basis points if between .75 and 1 and -3 basis points if less than .75.<br><br>Status: Active |

[23] Illinois Commerce Commission. *Commonwealth Edison Company Docket 22-0067*. September 27, 2022. For Ameren's most recent rate case see the following footnote.
[24] Illinois Commerce Commission. *Ameren Illinois company d/b/a Ameren Illinois Case Docket 22-0063*. September 27, 2022.

### 4.6.2 PIM Example: New York

Regulated electric utilities in New York operate under a variety of PIMs (known as Earnings Adjustment Mechanisms, or "EAMS") implemented as part of the state's Reforming the Energy Vision (REV) framework. Like the electric utilities in Maine, New York's distributors do not own generation assets. The perspective from New York regarding the design and implementation of PIMs may be relevant to Maine, given similar regulatory goals between both states.

New York utilities have been subject to the Reliability Performance Mechanism (RPM) and the Customer Service Performance Mechanism (CSPI) for many years. These mechanisms were initially created to prevent excessive spending cuts under Multi-Year Rate Plans.[25] The RPM measures distribution system reliability, including criteria such as frequency and duration of outages, remote network monitoring system performance and timely replacement of damaged poles. The CSPI measures the company's customer service quality using a broad number of indices. The utilities face negative revenue adjustments if certain performance thresholds across the RPM and CSPI are not met.

In addition to the state's existing PIMs, the REV framework introduced specific earning opportunities based on utility performance. While the Commission decides the EAM opportunity areas, each utility can propose their own performance incentives within these identified areas. Table 4.5 summarizes a sampling of EAMs that were approved for New York utilities that we believe may be applicable to Maine.

**Table 4.5: Selected EAMs in New York[26,27,28,29,30,31]**

| Category | Example | Details of approved EAMs |
|---|---|---|
| **Smart Meters** | AMI Customer Awareness – Staten Island (Con Edison 2017) | Increase customer awareness of AMI technology, features, and benefits in Staten Island.<br><br>Metric: Percent of customers aware of AMI benefits, measured through pre-and post-implementation surveys.<br><br>Incentive Structure: Reward-only<br><br>Reward: A $250,000 earnings adjustment will be granted if the company meets or exceeds the target awareness.<br><br>Penalty: None<br><br>Status: Inactive (Performance Period Concluded) |
| **Greenhouse Gas Emissions** | Demand Response | Designed to measure the maximum annual demand reduction resulting from NYSEG's Demand Response program. |

[25] New York State Department of Public Service, Staff Report and Proposal. *Reforming the Energy Vision*. *Case 14-M-0101*. April 24, 2014. p48.

[26] Consolidated Edison Company of New York Case 16-E-0060, 16-G-0061, and 16-E-0196. January 25, 2017.

[27] New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation Case 22-E-0317, 22-G-0318, 22-E-0319, and 22-G-0320 Joint Proposal. October 12, 2023.

[28] Consolidated Edison Company of New York Case 16-E-0060. April 25, 2019.

[29] Niagara Mohawk Power Company d/b/a National Grid Case 20-E-0380. January 20, 2022.

[30] New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation Case 19-E-0378, 19-G-0379, 19-E-0380, and 19-G-0381. November 19, 2020.

[31] Consolidated Edison Company of New York Case 16-E-0064 and 22-G-0065. July 20, 2023.

| Category | Example | Details of approved EAMs |
|---|---|---|
| | (New York State Electric & Gas 2023) | Metric: Load relief operationally available in a given year, measured above a baseline.<br>Incentive Structure: Reward-only<br>Reward: A maximum of 12 basis points ($2.6 million in RY1, $2.9 million in RY2, and 3.2 million in RY3)<br>Penalty: None<br>Status: Active |
| | Electric Vehicle CO2 Reduction (Rochester Gas and Electric 2023) | Incentivizes Rochester Gas and Electric to reduce GHG emissions by increasing the adoption of electric vehicles, such as battery EVs and plug-in-hybrid EVs.<br>Metric: Tons of lifetime C02 reduced<br>Incentive Structure: Reward-only<br>Reward: Based on targets met, the company can receive anywhere from $0.3 million to $1.8 million in RY1 and 0.3 million to $2.1 million in RY3.<br>Penalty: None<br>Status: Active |
| | Targeted GHG Reduction Metric (Con Edison 2019) | Incents Con Edison to reduce GHG by increasing the adoption of various technologies, such as EVs, solar, and heat pumps. Possible ways Con Edison can incentivize customers include creating advantageous rate structures, improving interconnection efficiencies, and providing rebates. Note that this list is not exhaustive.<br>Metric: Avoided metric tons of carbon dioxide<br>Incentive Structure: Reward-only<br>Reward: Based on targets, Con Edison can earn between $2.1 million and $7.6 million.<br>Penalty: None<br>Status: Inactive (Replaced/Revised) |
| **Affordability and Cost Control** | Non-Wires Alternatives Incentive (National Grid 2022) | Incents National Grid to pursue non-wires alternatives over traditional infrastructure investments.<br>Metric: The present value of net benefits projected of the NWA project portfolio.<br>Incentive Structure: Reward-only<br>Reward: The incentive is calculated as the sum of two components: 30% of the present value of net benefits from the NWA project and 50% of the difference between the projects initial cost forecast and its actual cost.<br>Penalty: None<br>Status: Active |

| Category | Example | Details of approved EAMs |
|---|---|---|
| | Electric Share the Savings (New York State Electric & Gas 2020) | Lower the unit cost of NYSEG's electric energy efficiency portfolio while increasing energy efficiency savings.<br>Metric: Lifetime annual electric energy efficiency savings (excluding LMI).<br>Incentive Structure: Reward-only<br>Reward: The company retains 30% of gross savings above a baseline target and budget amounts.<br>Penalty: None<br>Status: Inactive (Performance Period Concluded) |
| | Smart Building Electrification (Con Edison 2023) | Incentivizes greater energy savings from efficiency measures that facilitate a more cost-effective transition to building electrification.<br>Metric: Lifetime energy savings.<br>Incentive Structure: Reward-only<br>Reward: 2.5 to 6 basis points ($4.4 million to $11.8 million)<br>Penalty: None<br>Status: Active |
| **Interconnection** | Distributed Energy Resource Utilization (Rochester Gas & Electric 2020) | Incentivizes solar and energy storage interconnection.<br>Metric: Expected annual output from solar and energy storage interconnected within a rate year.<br>Incentive Structure: Reward-only<br>Reward: Up to 10 basis points<br>Penalty: None<br>Status: Active |

### *4.6.3 PIM Example: Hawaii*

Utilities in Hawaii are vertically integrated, which presents some applicability challenges for certain PIMs, but there are still valuable lessons to be learned from PIMs they have implemented and their approach to implementation. Hawaii devoted considerable time to researching and consulting various stakeholders to determine the best methods for implementing PIMs. In this section, we focus on PIMs from Hawaii that could be adopted by lines-only electric utilities.

The Hawaiian Electric Companies (HECO) report a broad set of metrics, with dozens of different metrics currently in effect.[32] While many of these metrics are merely reported, rather than PIMs offering financial incentives, the companies also currently operate under eight PIMs. A working group appointed by the PUC assisted with the conceptualization and design of Hawaii's current PIMs. Comments and proposals were also submitted by HECO and several other stakeholders, which the PUC considered in its final decision. Given the energy transition goals underpinning the state's PBR framework, many of the approved PIMs pertain to incorporating renewables and DERs onto the grid.

[32] Hawaiian Electric. *Performance Scorecards and Metrics.*

HECO's PIMs aim to achieve both energy transition goals and affordability for customers. However, some of the PBR tools employed by HECO apply to generation services, which are not relevant to Maine's IOUs. For example, to accelerate renewable energy adoption, the Renewable Portfolio Standard-Accelerated (RPS-A) PIM rewards utilities for exceeding clean energy goals, incentivizing faster integration of renewable sources like solar and wind.

Other HECO PIMs could be more applicable in Maine. For example, the Interconnection Approval PIM encourages faster approval processes for connecting new renewable energy systems to the grid.

To encourage affordability and equity, the Low-to-Moderate Income Energy Efficiency PIM pushes utilities to collaborate with energy efficiency programs, helping low-income residents participate in the energy transition by offering them ways to manage their energy use and potentially save money.

The HECO companies have had mixed success in meeting its PIMs objectives. In 2022 and 2023, HECO exceeded the PIM connection time threshold for its Interconnection Approval PIM. HECO achieved its renewable generation threshold for the RPS-A PIM in 2022, but not in 2023. None of the three HECO IOUs achieved the SAIFI, Call Center, or AMI Utilization PIMs thresholds in 2022 or 2023. In some cases when PIM thresholds were not achieved, HECO cited forces beyond the Company's control as presenting obstacles to achievement of the PIMs.[33]

Table 4.6 presents HECO's PIMs that are applicable to Maine, describing the metrics, rewards, penalties, and PIM status. Each PIM effects all Hawaiian Electric Company. Note that the list of PIMs is not comprehensive and excludes those less applicable to Main, such as reliability and call center PIMs, which are already in place.

**Table 4.6: Selected PIMs in Hawaii[34,35,36]**

| Category | Example | Details of approved EAMs |
|---|---|---|
| **Smart Meters** | Advanced Metering Infrastructure Utilization (2021) | Incent acceleration of the number of customers with advanced meters enabled to support time-varying rates and next generation DER programs.<br><br>Metric: Percentage of total customers with advanced meters delivering at least two of the three benefits ("Customer Authorization", "Energy Usage Alert", "Program Participation")<br><br>Incentive Structure: Reward-only<br><br>Reward: A minimum reward of, if performance is met, of $1 million and a maximum of $2 million.<br><br>Penalty: None<br><br>Status: Inactive (Performance Period Concluded) |

33 Hawaiian Electric Companies. *Notice Transmittal to Update Target Revenue through the Major Project Interim Recovery Adjustment Mechanism, Exceptional Project Recovery Mechanism, and Calculation of 2022 Performance Incentive Mechanism and Shared Savings Mechanism Financial Incentives*. June 1, 2023.
34 Public Utilities Commission of the State of Hawaii. *Docket No. 2018-0088, Decision and Order No. 37507*.
35 Public Utilities Commission of the State of Hawaii. *Docket No. 2018-0088, Decision and Order No. 37787*.
36 Public Utilities Commission of the State of Hawaii. *Docket No. 2013-0141, Decision and Order No. 34514*.

| Category | Example | Details of approved EAMs |
|---|---|---|
| **Affordability and Cost Control** | Low-to-Moderate Energy Efficiency (2021) | Incent collaboration between Hawaiian Electric and Hawaii Energy to deliver energy savings for low- and moderate-income customers.<br>Metric: Targets are based on residential hard-to-reach energy savings, peak demand reduction, and affordability program participation.<br>Incentive Structure: Reward-only<br>Reward: Shared savings<br>Penalty: None<br>Status: Inactive (Performance Period Concluded) |
| **Interconnection** | Interconnection Approval (2021) | Promotes faster interconnection times for DER systems of less than 100 kW. The company is penalized for underperformance and rewarded for exceptional performance.<br>Metric: The average number of business days to complete all steps in the company's control to interconnect DER systems.<br>Incentive Structure: Symmetrical<br>Reward: Based on tier, for example an average interconnection rate of 24 days in 2022 would reward $350,000 to Hawaiian Electric Company while an average of 18 would reward $1.1 million.<br>Penalty: Based on tier, for example an average interconnection rate of 33 days in 2022 would penalize $105,000 to Hawaiian Electric Company while an average of 39 would penalize $315,000.<br>Status: Active |
| | Grid Services (2020) | Incent the expeditious acquisition of grid services capabilities from DERs.<br>Metric: kW capacity of grid services acquired<br>Incentive Structure: Reward-only<br>Reward: Companies will receive a one-time award on per kW basis depending on the grid services acquired and the service territory it will serve.<br>Penalty: None<br>Status: Inactive (Performance Period Concluded) |

### *4.6.4 PIM Example: Ontario*

While PIM examples from Hawaii can offer some helpful perspective on PIM options and implementation, that state's island systems differ from the industry structure in Maine. This section reviews two PIMs that are currently under consideration in Ontario, a province which, like Maine, contains lines-only utilities operating under an independent system operator, and may therefore be more applicable. The selected examples address two of the four key policy areas of interest to the state: interconnections and greenhouse gas emissions. The table below provides a summary of each PIM, including its design, reward structure, and status.

Two other PIMs, not shown, related to reliability (SAIDI and SAIFI) are also under consideration in the province. Decisions regarding whether to implement these proposed PIMs will be made by the OEB in November 2025.

**Table 4.7: Selected PIMs Under Consideration in Ontario[37]**

| Category | Category & Example | Details of approved EAMs |
|---|---|---|
| **Greenhouse Gas Emissions** | System Utilization (TBD) | This PIM is intended to promote more efficient utilization of the electricity distribution system by offering financial incentives for aligning hourly demand with the system's maximum capacity.<br>Metric: Load factor<br>Incentive Structure: Reward-only<br>Reward: Currently being evaluated<br>Penalty: None<br>Status: Currently under consideration |
| **Interconnection** | Efficient DER Connections (TBD) | The PIM's function is to incent the timely connection of DERs.<br>Metric: Interconnection Time<br>Incentive Structure: Reward-only or Symmetrical<br>Reward: Currently being evaluated<br>Penalty: Currently being evaluated<br>Status: Currently under consideration |

## 4.7 Summary of PIMs in Practice

PIMs can be applied to a wide range of policy objectives and utilize diverse incentive structures. Utilities in other jurisdictions have operated under PIMs that address the four key areas of interest for Maine – Interconnection, Greenhous Gas (GHG) Emissions, Smart Meters, and Affordability and Cost Control. For instance, New York's Targeted GHG Reduction Metric provided an incentive to Consolidated Edison Company to reduce GHG emissions by increasing the adoption of technologies such as electric vehicles, solar panels, and heat pumps via measuring metric tons of avoided carbon dioxide. This example illustrates that there are ways to incent a lines-only utility to reduce GHG emissions.

In Illinois, Ameren's demand response PIM incentivizes peak load reductions through demand response programs. This mechanism, designed to reduce strain on the grid during peak hours, aims to lower GHG emissions and also seeks to enhance system reliability. Ameren's interconnection timeliness PIM provides an example of a potential tool that could address Maine's goal of facilitating the integration of DERs. By establishing an interconnection that tracks the number of days saved in the DER interconnection process, Ameren's PIM rewards or penalizes the utility based on performance relative to established benchmarks.

[37] Ontario Energy Board. Docket No. EB-2024-1029. Performance Incentive Mechanisms: Advancing Performance-based Rate Regulation.

Hawaii's regulatory framework placed a heavy emphasis on PIMs, some of which may offer helpful examples for Maine. But, some of the current PIMs in Hawaii apply more readily to integrated utilities than the lines-only IOUs in Maine. One potentially relevant PIM could be Hawaii's Interconnection Approval PIM, which promotes faster DER interconnection times by establishing performance tiers with corresponding rewards and penalties.

**PIMs: Vertically Integrated Vs. "Lines-Only" Utilities**

In Subsection 4.6, we presented "selected" PIMs that might have applicability to the utilities in Maine, setting aside PIMs designed to influence the generation portion of a utility's operations. In states with vertically integrated utilities, policy goals like Maine's plan to reduce greenhouse gas emissions (see Section 7.3), could warrant the introduction of PIMs to incent a transition to alternative fuel sources for power generation. Maine's utilities do not have the ability to determine the fuel mix of the state's power generation.

Integrated utilities in other states have operated under PIMs aimed at addressing policy goals similar to Maine's, but are not applicable to Maine's regulatory context. For example, Hawaii's RPS-A PIM, which rewards the Hawaiian Electric Company's (HECO) achievement of the State's Renewable Portfolio Standards.[38] This PIM provides a financial incentive for increasing total renewable generation in the HECO system. Central Maine Power (CMP) and Versant Power do not have the ability to make decisions about power generation, so this PIM cannot reasonably be applied in Maine.

Similar PIMs have been applied to vertically integrated utilities in North Carolina and elsewhere. Policymakers and regulators must take care not to assume that a PIM that works well in one jurisdiction can be copied and applied elsewhere, particularly if differences exist in the organization of the industry.

Across all three states examined above, there is a clear tendency to employ reward-only or symmetrical PIMs. This contrasts the SQIs in Maine, which employ penalty-only structures that penalize utilities for failing to meet benchmarks. While downside PIMs aim to provide accountability and protect customers, they are not ideal in all cases and can create cost recovery problems. The diversity of PIM structures across Illinois, New York, Hawaii, and beyond demonstrates the flexibility of PIMs to adapt to different regulatory environments and policy priorities, which may help Maine as it considers expanding the use of PIMs to achieve its own policy goals.

[38] Performance Incentive Mechanism Provision, Hawaiian Electric Company tariff, Effective June 1, 2021.

# 5 MULTI-YEAR RATE PLANS

Utilities in Maine have the ability to file Multi-Year Rate Plans (MYRPs) under the state's current rules. These "Alternative Rate Plans" can be filed at the discretion of the utility, and, in fact, the MPUC encouraged Versant Power to file a multi-year Alternative Rate Plan in its next rate application.[39] This section explains the benefits and challenges of MYRPs, as well as best practices for implementation. MYRPs can be used together with PIMs. As discussed in Section 4, PIMs can provide counter-pressure to potential cost-cutting that may lead to service quality degradation under a MYRP. Ultimately, we recommend that the MPUC adopt guidelines that help the state's utilities design quality, workable MYRPs.

## 5.1 Why Pursue MYRPs?

In recent years, capital and operating costs faced by electric utilities in North America have increased at a faster pace than the long-term average.[40] To maintain revenues commensurate with costs in an inflationary environment, utilities will generally propose new rates through a rate application filing before the state or provincial regulator. When cost pressures accelerate, rate applications are likely to become more frequent. This can be problematic because, often, such rate applications are viewed as administratively burdensome and costly.

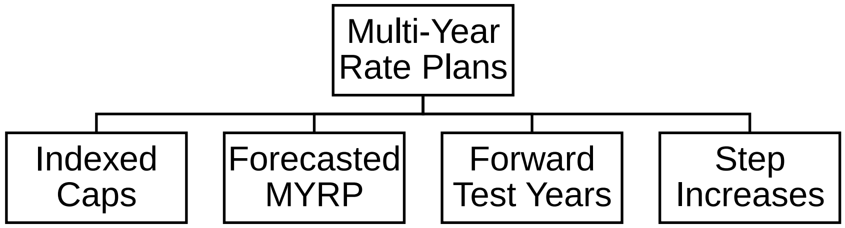
MYRPs are a category of alternative regulation tools that provide a framework for setting rates that can reduce the frequency of utility rate cases, facilitated by rate adjustments that either follow industry cost and productivity trends or align with the company's own costs—actual or forecasted. Thus, rather than establishing static rates that remain in effect until a future rate case—as under traditional COSR—a MYRP sets a schedule or formula that allows rates to change over the plan period. It is not until the end of the MYRP period that rates are reset through a comprehensive cost-based rate case. Most MYRP terms last three to five years.

Figure 5.1 depicts several categories of MYRPs are currently used by utilities in North America. This subsection will discuss the details of two of these forms of MYRP—indexed caps and forecasted MYRPs. The other two, forward test years and step increases, are quite similar to the forecasted MYRP approach, relying on information regarding expected costs.

[39] Maine Public Utilities Commission. *Order: Request for Approval of Distribution Rate Change Pursuant to 35-A M.R.S. 307. Docket No. 2023-00336*. March 13, 2025.

[40] Crowley, Nicholas, and Daniel McLeod. *Trends and drivers of distribution utility costs in the United States: A descriptive analysis from 2008 to 2022. The Electricity Journal.* Volume 37, Issue 3. April 2024.

**Figure 5.1: Forms of MYRP**




MYRPs have existed for decades in some jurisdictions, but no two MYRPs are exactly alike. Depending on their design, MYRPs can include cost efficiency incentives for the utility, which may yield higher profits to the utility and slower rate escalation to customers.[41] If costs exceed expectations, however, returns may decline, with the impacts to net income associated with cost overruns borne by shareholders. Some, but not all, forms of MYRP may be considered PBR. The nature of a plan's incentives depends on its design. For example, while indexed cap plans like price caps and revenue caps are generally considered to be a fundamental form of PBR, formula rate plans, which adjust rates according to a utility's actual costs, would not be considered a form of PBR. We discuss the different forms of MYRPs in Subsections 5.2-5.4, below.

MYRPs of any kind may also layer into the framework performance incentives and efficiency targets for the utility. The goal with these additional mechanisms is to provide the utility with incentives to find efficient ways to improve service quality or promote policy objectives. We discuss such measures, known as PIMs, in Section 4.

If designed well, MYRPs can benefit both utilities and consumers. Utilities gain more predictable revenues and may obtain stronger incentives for cost control and innovation. Consumers may benefit from more stable rates, improved utility performance, and the potential for lower rates in the long run as efficiency gains are shared. However, these plans also carry risks. Customers may need to tolerate that their utility has the potential to earn profits above the allowed rate of return if costs decline over the PBR term. Likewise, utilities may face financial strain if costs rise unexpectedly. As discussed below, regulators may pair MYRPs with other mechanisms like earnings sharing or reopener clauses to mitigate these risks and maintain a balance between utility and consumer interests.

Table 5.1 highlights key advantages and challenges of MYRPs.

[41] Crowley, Nicholas, and Mark Meitzen. *Measuring the price impact of price-cap regulation among Canadian electricity distribution utilities*. *Utilities Policy.* Volume 72. October 2021.

**Table 5.1: Advantages and Challenges of Multi-Year Rate Plans**[42]

| ADVANTAGES | CHALLENGES |
|---|---|
| **Stable rates and revenue:**<br>• Generates relatively predictable revenue during the multi-year rate plan period.<br>• Provides rate stability for consumers. | **Regulatory and intervenor resistance**<br>• May not be comfortable with a change, particularly if it's associated with rate increases.<br>• May require legal changes regarding utility regulation. |
| **Cost Efficiency Incentives**<br>• Increases the incentive to find cost efficiencies. | **Data requirements:**<br>• May require detailed revenue requirement forecasts at the account-level. |
| **Reduced regulatory burden**<br>• Reduces the frequency of rate applications. | **Rate stay-out periods:**<br>• Restricts rate case frequency. |

## 5.2 Indexed Caps (Price and Revenue Caps)

The state of Maine has some past experience with indexed caps. Central Maine Power (CMP) operated under a price cap, which is a form of indexed cap, until 2013. This form of PBR may be worth revisiting to address goals of cost control and affordability. Maine's utilities are currently permitted to propose an indexed framework as part of a rate application.

Indexed cap MYRPs annually adjust prices or revenues based on a formula of factors beyond the control of the company. This formula, known as the "I-X" formula, sets either prices or revenues such that the utility's costs and allowed revenues are temporarily de-linked. This allows the utility to retain profits beyond its allowed ROE over the plan term if it is able to find cost efficiencies. Only at the end of the plan term are rates reset according to the utility's cost to serve. This process is known as "rebasing." The primary objective of indexed cap regulation is to improve the cost efficiency of the utility, though, indexed caps may also provide other benefits including a reduction in the frequency of rate applications over time.

The I-X formula consists of an inflation factor (I) less industry productivity growth (X). The formula is derived from a fundamental economic principle of market competition, which states that over the long run in perfect competition, the costs and revenues of a firm are equal.[43] This principle, translated into the I-X formula, sets a price or revenue growth trajectory that mimics what would occur in competitive markets. (The derivation of the I-X formula can be found in Appendix C.) Thus, even though utilities do not experience perfect competition for distribution services, for example, the regulatory structure under an indexed cap can provide cost efficiency

[42] See, for example: Kenneth W. Costello. *Multi-year rate plans are better than traditional ratemaking: Not so fast*. *The Electricity Journal.* April 2023.

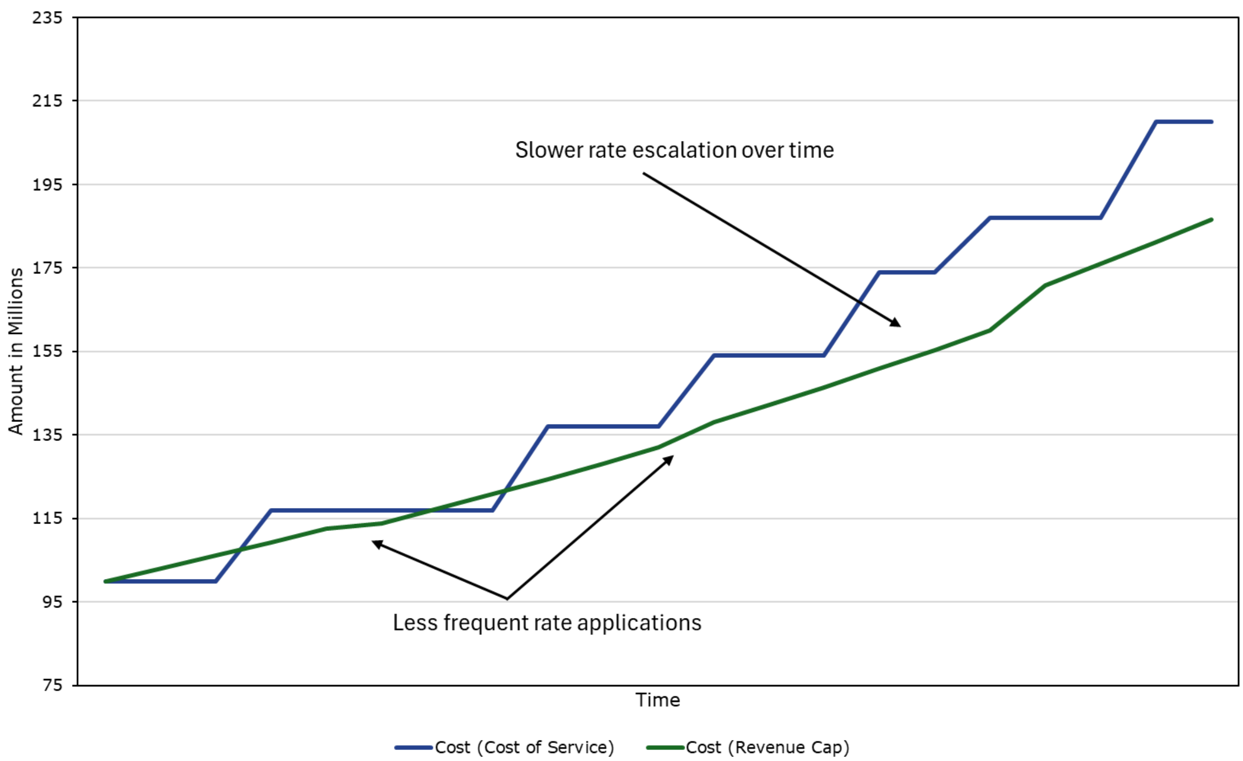
[43] If costs were lower than revenue in the long run, other firms would enter the market and bid down prices such that eventually revenue would equal costs. If costs were higher than revenue in the long run, firms would either leave the market or go bankrupt.

pressures akin to market competition. In contrast, traditional rate-of-return regulation promotes only limited cost efficiency incentives, as cost recovery may be granted on any expenses not disqualified by the regulator.

The power of indexed cap PBR plans to provide cost efficiency incentives lies in the profit motive of the utility. In the short run, the utility may manage to earn above average returns by reducing costs. As costs are reduced, the utility's rates (or revenues) remain stable according to the I-X formula, allowing for higher earnings. At the end of the PBR term, the utility "rebases" rates according to costs. Theoretically, these costs will be lower than they would have been otherwise, as the cost efficiency incentives of the cap will have driven enhanced cost reduction. As a result, the next generation of rates will be lower than they would have been under traditional COSR.

Figure 5.2 provides an illustrative visualization of this concept. As shown in this graph, theory suggests that cost efficiency incentives of indexed caps reduce total utility costs over time relative to traditional cost-of-service regulation. While rates are not immediately reduced, rates are lower over the long term via rate rebasing.

**Figure 5.2: How PBR Can Slow Rate Escalation over the Long Term**




A resolution to accrue benefits over the long term is necessary for PBR to work properly. As recognized by the Alberta Utilities Commission, under price caps, "customers get the benefit of a more efficient utility and lower cost structures for the same or better utility service over the long term."[44] In the short run, earnings may appear lower or higher what might be experienced

[44] Alberta Utilities Commission. *AUC-Initiated Review Under the Reopener Provision of the 2018-2022 Performance-Based Regulation Plans for ATCO Electric and ATCO Gas*. May 24, 2024, p. 25.

under COSR, even while costs decline. If the regulator confiscates higher earnings or provides recovery for underearning through rates, the incentives of indexed caps dissolve. The regulatory economist Dr. Dennis Weisman described this phenomenon as follows:

> "[…]higher than normal earnings may simply reflect the stronger incentives for efficient performance under price cap vis a vis earnings regulation. Should this be the case, these additional earnings would not exist but for the regulator's commitment to allow the regulated firm to be the residual claimant for its realized efficiency gains. In other words, the ability on the part of the regulator to appropriate these earnings may exist only because the firm believed the regulator would not take unfair advantage of this opportunity. It follows that because PCR [price cap regulation] breaks the link between prices and costs, it must also break the link between higher than normal profits and excessive rates […]"[45]

### *5.2.1 Price Caps*

Price caps are a form of indexed cap that limit adjustments to customer rates over a pre-specified period of time. The price cap allows rates and costs to diverge as the utility works to find cost efficiencies to earn superior returns. At the end of the price cap term, typically around five years, the utility files a "rebasing" rate application, resetting rates according to its cost to serve.

Although customer price growth is restricted under this approach, revenues are not restricted. The utility can increase its revenue over the plan term through sales growth. Thus, the utility can improve profits both by increased sales and by cost reduction. Conversely, however, the utility can experience revenue losses, and therefore reduced profits, if sales declines occur and/or if costs increase.

Under a price cap, energy, demand, and customer charge adjustments are made each year of the MYRP term according to an inflation rate minus industry productivity formula, generally called the "I-X" formula. By common practice, the inflation rate is updated each year using government data, while the X factor remains fixed over the plan term.[46] Table 5.2 depicts the mechanics of a price cap. Note that for the Residential customer, both the customer and energy charges are adjusted each year by the percentage obtained from I-X. For the Business customer, the customer, energy, and demand charges are all adjusted by this same percentage.

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[45]Dennis L. Weisman. *Is There Hope' for Price Cap Regulation. Information Economics and Policy, Volume 14(3).* September 2002, pp. 363-364.
[46] The X factor is generally calculated by productivity experts.

**Table 5.2: Illustrative Example of a Price Cap**

| Term Year | I | X | I-X | Residential | | Business | | |
|---|---|---|---|---|---|---|---|---|
| | | | | Customer | Energy (kWh) | Customer | Energy (kWh) | Demand (kW) |
| Year 1 | | | | $10.00 | $0.080 | $120.00 | $0.080 | $3.000 |
| Year 2 | 2.00% | -1.50% | 3.50% | $10.35 | $0.083 | $124.20 | $0.083 | $3.105 |
| Year 3 | 2.10% | -1.50% | 3.60% | $10.72 | $0.086 | $128.67 | $0.086 | $3.217 |
| Year 4 | 2.00% | -1.50% | 3.50% | $11.10 | $0.089 | $133.17 | $0.089 | $3.329 |
| Year 5 | 2.50% | -1.50% | 4.00% | $11.54 | $0.092 | $138.50 | $0.092 | $3.463 |

In most current price (and revenue) cap plans currently in place in North America, the X factor is set equal to zero, even though analysis of industry data indicates negative productivity growth in recent years. Under the assumption of a zero X factor, prices adjust by the rate of inflation.[47] If an empirical X factor that is negative were used to set a price cap, prices would be permitted to rise at a rate slightly above the rate of inflation. This phenomenon correlates to the fact that cost growth across the utility industry has recently exceeded the rate of inflation in the broader economy.

### *5.2.2 Revenue Caps*

Many of the incentive qualities of price caps also apply to revenue caps. As with price caps, both the utility and its customers can obtain benefits through cost efficiencies under a revenue cap if the plan is structured properly. However, some features distinguish revenue caps from price caps.

One difference involves the structure of the PBR formula. Like price caps, revenue caps rely on a formula that includes inflation and productivity growth. However, the revenue cap formula differs from the price cap formula in its inclusion of a growth factor set equal to annual growth in the number of customers. Thus, the formula under a revenue cap sets revenues according to "I-X+G," where G is equal to the annual growth in the number of the utility's customers. This formula is derived in Appendix C.

Another difference involves the utility's operation under revenue decoupling. Revenue decoupling is generally not included in price cap plans. However, most revenue cap plans in North America rely on some form of revenue decoupling to ensure that revenues do not exceed the cap over the PBR term. The I-X+G formula adjusts the utility's allowed revenue each year, and the revenue decoupling mechanism returns to customers any revenue that is collected over the cap (for example, from higher than expected sales volumes). In fact, if a revenue cap operates without a mechanism to return excess revenues to customers, it is effectively a price cap.[48]

A third difference between price and revenue caps pertains to sales risk. For a utility with concerns about falling sales volumes, a revenue cap with revenue decoupling may be preferred because such an approach would provide revenue irrespective of changes to sales volumes. Revenue caps adjust the utility's allowed revenue according to the I-X formula, and revenue

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[47] Inflation is generally a weighted average of labor inflation (e.g. "average weekly earnings") and non-labor inflation (e.g., CPI), based on company splits of labor and non-labor operating expenses.
[48] Crowley, Nicholas, and McLeod, Daniel. *Making Sense of Multi-Year Rate Plans*. 2024.

decoupling adjusts rates according to differences between the utility's expected and actual sales. Together, a revenue cap with decoupling provides the utility with revenue adjustments each year of the plan proportional to industry average cost growth regardless of sales. In this way, a revenue cap approach with decoupling (relative to a price cap framework) can reduce risk for a utility concerned about falling demand for electricity, particularly if it recovers some of its fixed costs through an energy charge.

Such an approach does not eliminate risk, however. Under both price caps and revenue caps, the utility faces the risk that its costs could rise faster than the annual adjustment in revenues (or rates). If costs rise faster than revenue adjustments provided by I-X, the utility may need to manage with lower earnings until the end of the PBR term, at which time it can rebase its rates according to costs.

Table 5.3 depicts an illustrative example of a revenue cap. In Year 1, the utility's revenue requirement is set equal to its cost to serve ($1 billion). In each subsequent year of the five-year plan, the allowed revenue is adjusted according to an inflation rate (I), the X factor, which is based on industry productivity, and company-specific growth in the number of customers served (G). The inflation rate is updated each year of the plan, using published government data. The company also updates G using its most recent annual customer count growth rate.  As with the price cap formula, the X factor remains fixed over the plan term. The allowed revenue in each year equals the previous year's allowed revenue, adjusted by I-X. A revenue decoupling mechanism can be used to true up realized revenues and allowed revenues each year.

**Table 5.3: Illustrative Example of a Revenue Cap[49]**

| Term Year | I | X | G | I-X+G | Revenue Cap (Millions USD) |
|---|---|---|---|---|---|
| Year 1 | | | | | 1,000 |
| Year 2 | 2.00% | -1.00% | 1.25% | 4.25% | 1,043 |
| Year 3 | 2.10% | -1.00% | 1.00% | 4.10% | 1,085 |
| Year 4 | 2.00% | -1.00% | 0.75% | 3.75% | 1,126 |
| Year 5 | 2.50% | -1.00% | 1.00% | 4.50% | 1,177 |

### *5.2.3 Setting the Base Year*

Indexed caps operate by escalating a set of prices (or a company's revenue requirement) using cost information filed at the commencement of the PBR term. The revenue requirement used to set initial rates is called the "base year." Because of fluctuating costs year-to-year, the choice of base year can have a substantial influence on a utility's revenues over the PBR term. Furthermore, if the base year does not capture large, planned expenditures that will annually continue during the PBR term, the I-X formula may not provide sufficient revenue enough to meet the firm's cost of service. This problem may prove particularly troublesome for a utility that plans large plant additions during the PBR term, which might give rise to increased depreciation and operating expenses beyond the I-X formula's revenue adjustment mechanism.

The cost elements included in the first year, or base year of the program, may correspond to the cost-of-service test year revenue requirement that is recovered by the first year of new rates. It

[49] Note that the X factor for a revenue cap generally differs from the X factor for a price cap.

may also be the case, however, that the test year and base year are different. When this occurs, the base year, which sets the PBR term's going-in rates, contains adjustments to a test year to better align the base year with actual expenditures expected during the PBR term.

It is important to select a base year that is reflective of expenditures and costs for the utility over the duration of the PBR plan. Choosing a year with unusually low investment that does not reflect investment patterns over the term of the PBR plan can lead to an inability to fully recover the costs of future investments. Choosing a year with an unusually high level of investment that does not reflect investment patterns over the term of the PBR plan can lead to over recovery at the expense of the consumer. Therefore, it is important to choose the appropriate base year, including adjustments if necessary.

### *5.2.4 Annual PBR Filings*

Utilities operating under PBR submit annual filings to communicate rate changes for the coming year associated with a revenue cap or price cap adjustment. The annual review generally includes updates to all relevant elements of the PBR framework:

- *Inflation* – the formula will be updated to use the most recent government inflation numbers for the chosen inflation measure.
- *X factor* – by convention, in most frameworks, the productivity factor, or "X factor," remains static over the PBR term. However, the X factor could be updated each year with the most recent industry data.
- *Stretch Factor* – this mechanism provides immediate benefits to customers, and, like the X factor, generally remains static over the PBR term.
- *Exogenous Factors (Y and Z factors)* – the utility may be allowed to recover additional costs, as explained in subsections below.
- *Capital supplements* – the PBR plan may also include provisions for the recovery of certain capital costs.
- *Earnings sharing* – some PBR frameworks include earnings sharing mechanisms that return a portion of earnings to customers.
- *PIMs* – rates may be adjusted for penalties or rewards based on performance under these pre-defined mechanisms.

The primary purpose of an annual filing under PBR is for the regulated utility to set rates for the forthcoming year. Other elements may also be included in the annual filing, but a streamlined annual review process with fewer components and fewer intervenor questions is more likely to yield the regulatory efficiencies commonly associated with PBR.

### *5.2.5 Common Elements of Indexed Cap Plans*

Indexed price and revenue cap formulas are frequently supplemented with additional elements to address specific challenges faced by regulators or utilities. These include a stretch factor; a string of letter factors: Z, Y, and K factors; and other guardrails. The purpose of these additional elements is to provide benefits to customers, change the risk profile of the PBR plan, and/or to provide revenue support that is required outside of the I-X formula. Indexed caps may also be paired with an ESM (Section 5.2.5.8).

#### 5.2.5.1 The Inflation Factor

The inflation factor is the component of an indexed cap plan that reflects the expected changes in the prices faced by the regulated utility industry. An indexed cap PBR formula should be designed to produce rates that reflect inflationary pressures on input prices, less adjustments for productivity changes, that a company is expected to experience from year to year during the term of the plan. The purpose of the inflation factor is to capture increases in the utility's input prices that are driven by macro-economic forces.[50] In this sense, the inflation factor should account for price changes that are external to the utility's management.

There are two basic approaches to the inflation measure to be used in a PBR plan. The first approach is to use a measure of economy-wide *output* price inflation, such as the Gross Domestic Product Price Index (GDP-PI). This approach is more common among PBR plans in the United States. The second approach, which is more common in Canadian plans, uses some measure of industry *input* price inflation. The Fixed Weighted Index (FWI) of average hourly earnings is a good example of an input price measure of inflation. An input price measure of inflation captures the prices of inputs purchased by the utility, while an output price measure reflects the prices of goods and services purchased by end consumers.[51]

**Table 5.4: Recommendations for Inflation Factors**

| | |
|---|---|
| Indexed Cap Inflation Factors | *If the Maine IOUs operate under an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that an inflation factor be included in the PBR formula (I-X). The inflation factor should be established to reflect the electric utility sector's annual input price growth. If an output price measure of inflation is used, the X factor must be adjusted accordingly.* |

#### 5.2.5.2 The X Factor

The productivity offset, or X factor, is a key element of indexed cap plans. Coupled with the inflation factor in the I-X formula, the X factor is a mechanism designed such that changes in utility revenues reflect the change in industry input prices and the rate of industry productivity growth. Accordingly, combined with the I factor, I–X represents the expected unit cost performance of an average performing company in the industry when productivity is defined with customers as the output measure.[52] Together, the inflation and X factors mimic the pressures of a competitive market by pegging company revenues to its performance in comparison to its peers. To the extent that the firm is more productive than its peers and is able to produce at lower costs, it earns a superior return. Conversely, firms that are less productive than the

[50] Alberta Utilities Commission. *Decision 2012-237*. p. 32.

[51] Using an input price approach simplifies the X factor calculation. If an output price measure were used, the X factor would be modified to include a TFP growth differential between the economy and the utility, as well as an input price differential between the economy and the utility. No such differential is required to set the X factor when using an input price measure of inflation. Instead, the X factor under an input price inflation measure simply equals industry TFP growth.

[52] Where the unit cost equals total cost per customer.

industry average earn lower returns.[53] According to economic principles explained in Appendix C, the use of expected productivity in setting the X factor provides the appropriate level of attrition relief to the regulated firm under an indexed cap.

In some cases, regulators have set the revenue or price cap equal to input price inflation with a zero or arbitrary X factor. However, this is not the correct approach and could cause problems for the utility operating under the cap. The I factor only captures the change in input prices faced by the industry. It does not capture the required change in input *quantities.* A simple example illustrates the problem with this approach. Suppose a utility must replace a large portion of its poles and suppose the price of a single pole does not change from year to year. In this case, the I factor would equal zero, because the input price remains unchanged. If revenue were allowed to increase only by the I factor, the utility's revenue growth from one year to the next would equal 0%. This would be an insufficient revenue increase, because the change in the quantity of poles will increase costs, such that total costs exceed total revenues. Although this is a simplified example, this concept, in essence, is what the X factor represents: industry productivity, or a change in input quantities relative to the change in outputs. By setting the revenue cap with both an empirical inflation measure and an empirical productivity measure, the revenue cap will be set such that utility revenues are allowed to grow with the industry cost growth experience.

Because the I-X formula aims to provide pressure that imitates the competitive market that is external to the regulated firm, the X factor is generally set using industry data, not data specific to the company under the revenue cap. A TFP growth study using a sample of peer companies is typically used to set the appropriate value for the X factor.[54] Another method, known as the Kahn Methodology, provides similar information using financial data—as opposed to "real outputs" measured in TFP growth studies—and is employed in the price cap regulation of U.S. oil pipelines.

**Table 5.5: Recommendations for X Factors**

| | |
|---|---|
| Indexed Cap X Factors | *If the Maine IOUs operate under an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that an X factor be included in the PBR formula (I-X). This X factor should be calculated on the basis of an industry TFP growth or Kahn Methodology.* |

#### 5.2.5.3 Stretch Factors

The primary objective of indexed cap PBR frameworks is to provide the regulated utility with an incentive to seek improvements in cost efficiency during the PBR term. Under an I-X cap and in the absence of any other plan elements, cost efficiency gains are entirely retained as profits to the utility's shareholders until the end of the PBR term, at which time customers would benefit in the form of lower rates (as the revenue requirement is reset based on a cost-of-service rate

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[53] William J. Baumol. *Productivity-incentive clauses and rate adjustment for inflation. Public Utilities Fortnightly.* 1982.

[54] If the X factor were to be based on changes in the regulated firm's productivity, price cap regulation would function in similar fashion to cost of service regulation. Jeffrey I. Bernstein and David E.M. Sappington. *Setting the X Factor in Price-Cap Regulation Plans. Journal of Regulatory Economics*, *Vol. 16, 1999*. p. 9.

case). Regulators may prefer that some of these gains in cost efficiency are returned to customers immediately, rather than retained by the utility until the end of the PBR term.[55] A "stretch factor," S, reduces the growth in prices (or revenues) under the PBR term, by incorporating an additional factor in the I-X formula.

For example, the price formula with a stretch factor is:

$$\%\Delta price = I - X - S \tag{5.1}$$

Where S is generally a positive percentage in the range of 0.00% to 0.40%. The regulator subtracts the stretch factor from the I-X cap to reduce the rate of growth in price and share the expected cost reductions with customers. Thus, customers will face price growth slower than what theory suggests would be expected in a competitive market.

A stretch factor will not change the incentives for efficiency—no matter what price the regulator sets, the firm maximizes profits by containing cost and improving efficiency. Instead, setting a stretch factor is a question of distributional fairness of over what time frame consumers are entitled to a portion of firm-specific efficiency gains through lower utility rates.

The academic literature has alluded to a connection between cost benchmarking results and stretch factors.[56] However, in practice, regulators have calibrated stretch factors without support from an empirical cost benchmarking study. More commonly, benchmarking studies have informed the choice of stretch factor, but relies heavily on "regulatory judgement." We recommend that stretch factors use cost benchmarking information, rather than blind judgement, as the data is publicly available via the FERC Form 1.

**Table 5.6: Recommendations for Stretch Factors**

| | |
|---|---|
| Indexed Cap Stretch Factors | *If the Maine IOUs operate under an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a stretch factor be included in the formula (I-X-S). This stretch factor should be company-specific informed by an industry cost benchmarking analysis.* |

### 5.2.5.4 Z Factors

Under indexed cap plans, the utility generally agrees not to file rate applications during the term of the plan. This means that companies operating under price caps or revenue caps must manage with a constrained spending envelope over a period that could be five years or longer.

[55] Another reason cited for introducing a stretch factor is a desire to return a share of reduced regulatory burden to customers. The stretch factor might also serve as a signal to firms and stakeholders of what the regulator expects the firm to do. Some efficiency changes a utility might seek to make could incur more stakeholder opposition from employees or customers if the benefits of those changes do not pass through to customers in a timely fashion. It is also worth noting that omitting a stretch factor might allow the firm to remain "statically inefficient" over the PBR term, continuing to operate at a higher cost level than its peers.
[56] Lowry, M.N., Getachew, L., Hovde, D. *Econometric Benchmarking of Cost Performance: The Case of US Power Distributors*. The Energy Journal 26 (3). 2005. p. 75–92

Most PBR frameworks include provisions to account for costs that may rise during this time for reasons beyond the control of the utility's management.

One type of costs often recovered outside of a price or revenue cap are exogenous events—one-time costs that arise for reasons clearly beyond the utility's control. The mechanism to recover such costs is called a "Z factor."[57] The Z factor allows for an adjustment to a company's revenues to account for a significant financial impact (either positive or negative) of a one-time event outside of the control of the company and for which the company has no other reasonable opportunity to recover the costs within the PBR formula. Generally, a relevant Z factor event is one that is unknown (and unknowable) to the company at the start of the PBR regime; that has a substantial impact on the company's earnings; and for which both the event and the financial impact of the event on the company's earnings are largely beyond the company's control.[58] Most indexed cap PBR plans set a minimum threshold (i.e., "materiality") for Z factor events, under which costs are not eligible for Z factor recovery.

In Massachusetts, for example, utilities under PBR can recover, through a Z factor, incremental costs resulting from changes in tax laws that uniquely affect the relevant industry; accounting changes unique to the relevant industry; and regulatory, judicial, or legislative changes uniquely affecting the industry.[59] Other examples that might be eligible for recovery through a Z factor are as follows:

- Government policy changes;
- Judicial, legislative, or administrative changes, orders, or directions;
- Major environmental events (e.g., a major seismic event, flood, fire, pandemic);
- Major labor disruption or supply chain event;
- Acts of war, terrorism, or violence;
- Changes in accounting treatment, standards, or policies; and
- Changes in revenue requirements due to regulatory decisions.

Exogenous factors like the Z factor provide guardrails for the PBR framework, to mitigate the risk that major unforeseen events will impact the utility's finances so materially as to potentially inflict damage on customer service quality or the utility's ability to raise capital.

**Table 5.7: Recommendations for Z Factors**

| | |
|---|---|
| Z Factors | *If the Maine IOUs operate under an indexed cap or forecasted MYRP approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a Z factor be included in the PBR framework. The Z factor should be company-specific and have a materiality threshold roughly in line with thresholds seen in other jurisdictions.* |

[57] See, for example: BC Utilities Commission, Decision and Order G-388-21, 51. Also see, Alberta Utilities Commission, Decision 2012-237. p. 108.
[58] Dennis Weisman. *Assessing the Treatment of Capital Expenditures in PBR Plans*. *Fiscal 2020 to Fiscal 2021 Revenue Requirement Application.* Ch. 11. Appendix GG. p. 36.
[59] Massachusetts Department of Public Utilities. *Docket D.P.U. 17-05*. p. 396

#### 5.2.5.5 Y Factors

During the PBR term, portions of a utility's costs may be volatile for reasons other than one-time exogenous events. Ongoing costs, like fuel to power generation, may fluctuate dramatically, such that they diverge from the indexed cap formula but do not meet the criteria for a Z factor.

Y factor costs are those recurring exogenous costs that do not qualify for Z factor treatment and that should be directly recovered from customers or refunded to them. The purpose of Y factors is to allow for separate cost recovery of those costs outside of management's control, and are therefore recovered outside of the price or revenue cap. Y factor costs could either be costs the company is required to pay to a third party (such as the electricity purchases on the open market) or other regulator-approved costs incurred by the company for flow through to customers.[60]

Some jurisdictions use a term other than "Y factor" when referring to flow-through costs, though these plans still include provisions for such costs.[61] In these cases, a different name fulfills the same purpose as Y factors. For example, FortisBC recognizes "flow-through" costs often through variance accounts. These items include depreciation expense, insurance premiums, income and property taxes, interest expense, the cost of energy, and certain forecasted O&M expenses. Variances related to these items are captured in each of the utility's general flow-through deferral accounts. Other revenue requirement variances are also flowed through to rates using specific deferral accounts.[62] The Hawaiian utilities operating under PBR recover costs pertaining to energy costs and purchased power, pension costs, demand-side management costs, renewable energy infrastructure program costs, under "cost trackers," which is a term that is generally synonymous with the term Y factor.

Examples of Y factors explicitly listed by the Alberta Utilities Commission as eligible include system operator fees, farm transmission costs, costs arising from Commission directives, tax changes, municipal fees, load balancing deferral accounts, and production abandonment costs. In Quebec, the Y factor included retirement costs, which have significant volatility, but the Régie determined that the Y factor would not include tax changes, which, if large enough, could be recovered through the Z factor.[63]

Our research indicates that the classification of costs as eligible for Y factor, or flow-through, treatment varies by jurisdiction. To some extent, these differences may arise because of differences in industry structure between different regions. Like the Z factor, Y factors provide stability to the utility during the rate case stay-out period, so that it recovers potentially volatile costs outside of its control without requiring a new rate case.

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[60] See, for example: Alberta Utilities Commission. *Decision 2012-237*. p. 131.

[61] The term does not appear to be used in Ontario, Massachusetts, Hawaii, or by FortisBC.

[62] BC Utilities Commission. *Orders G-165-20* and *G-166-20, 65*.

[63] Régie de l'énergie. *Décision sur l'établissement des modalités du mécanisme de réglementation incitative*. *D-2019-060*. May 16, 2019. p. 53.

**Table 5.8: Recommendations for Y Factors**

| | |
|---|---|
| Y Factors | *If the Maine IOUs operate under an indexed cap or forecasted MYRP approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a Y factor be included in the PBR framework. The Y factor should be company-specific and the costs eligible for Y factor treatment should be clearly defined at the outset of the PBR term.* |

#### 5.2.5.6 K (Capital) Factors

Electric utilities require capital outlays to maintain and grow service in accordance with their obligation to serve customers and, recently, electric utilities across the US have increased capital spending on new technologies to support electrification of the economy. Utility revenue constraints under PBR therefore create concerns with respect to maintaining service. Revenue deficiencies may arise if the indexed cap base year revenue requirement does not reflect capital needs in subsequent years during the PBR term, or if capital expenditures exhibit high variability. As such, PBR frameworks generally contain revenue support for capital expenditures.

Different jurisdictions in which utilities operate under indexed cap PBR plans have different ways of determining what capital should be recovered under a formula and different ways of managing revenue recovery of capital outside of the I-X formula. Because every utility is different and many PBR regimes are still in their early stages, the industry has not settled on best practice approach to recovering capital under PBR frameworks.

Approaches have also differed across time within jurisdictions. For example, the first generation PBR plan for Alberta distribution utilities allowed for capital tracker filings, which generated excessive regulatory processing, leading ultimately to a change in the second generation PBR plan. Similarly, the British Columbia Utilities Commission (BCUC) found that FortisBC, Inc. could not sufficiently recover revenue for capital spending under its 2014-2018 plan, such that capital was removed from formula treatment under the 2018-2022 plan and is now recovered on a forecasted cost-of-service basis.

A lack of homogeneity across jurisdictions and across time suggests two things. First, although supplemental revenue for capital is common across PBR plans, regulators have flexibility in setting the design of capital recovery mechanisms. Second, the success of each capital supplement methodology is not well tested, as most methods have only existed for a short span of time. Where empirical information on the benefits or limitations of each approach is lacking, economic theory can provide guidance.

There are many differing methods of capital cost recovery under PBR. Table 5.9 provides a summary.

**Table 5.9: Summary of Capital Recovery Approaches Under PBR**

| Approach | Jurisdictions | Methodology |
|---|---|---|
| Forecasted Capital | British Columbia; Australia | In the PBR proceeding to set initial rates, the utility establishes a forecast of capital spending costs over the PBR term and recovers these costs through rates. |
| Cost-of-service (capital trackers) | Massachusetts | Massachusetts Electric d/b/a National Grid has the ability to recover capital expenditures using annual cost trackers. |
| Project-Specific capital trackers | Ontario; Hawaii | Utilities may recover costs for projects that meet certain criteria. Known as the Exceptional Project Recovery Mechanism in Hawaii,[64] and the Incremental Capital Module in Ontario.[65,66] |
| K-Bar | Massachusetts, Alberta | This approach provides a capital spending envelope based on the utility's own trend in historical capital spending.[67] |

The advantage of the Forecasted Capital approach is that utilities receive their expected revenue shortfall for capital expenses, while still maintaining some incentive to contain those expenses. For instance, in British Columbia, the difference between actual and forecasted expenses are subject to an Earnings Sharing Mechanism, meaning that if the utility spends less than the forecast, it is able to retain some of these savings as profit. Additionally, this approach reduces regulatory burden by setting the forecast before the term begins, and leaving any variances between actual and forecasted spending to be handled mechanistically through the ESM rather than through annual cost-of-service proceedings. The primary disadvantage of the Forecasted Capital approach is that it may incentivize the utility to over-forecast capital expenses if it is able to retain any savings as profit. However, tradeoff can be mitigated through prudency reviews before and after the PBR term, or by forecast penalty terms.

A cost-of-service approach to capital expense recovery involving annual capital trackers has the advantage of minimizing financial risk to the utility, which may be essential during a period of transition in which significant capital investment is necessary. Well-designed capital trackers can reduce the regulatory lag for utilities, increase the willingness of utilities to invest in critical

[64] Hawaii Public Utilities Commission. *In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval to Commit Funds in Excess of $2,500,000 (excluding customer contributions) for the PZ.005125 – Kahe-Waiau 138 kV Undergrounding Project and to Recover Costs through the Exceptional Project Recovery Mechanism. Decision and Order No. 38451 Docket No. 2021-0086*. p. 62.

[65] Ontario Energy Board. *An Application by Hydro One Networks Inc. for [an order approving distribution rates], EB-2008-0187*. May 13, 2009.

[66] Note, Ontario distribution utilities may also recover capital costs under another mechanism, known as the Advanced Capital Module.

[67] For more information, see here: Alberta Utilities Commission. *Rebasing for the 2018-2022 PBR Plans for Alberta Electric and Gas Distribution Utilities, Decision 22394-D01-2018*. February 5, 2018.

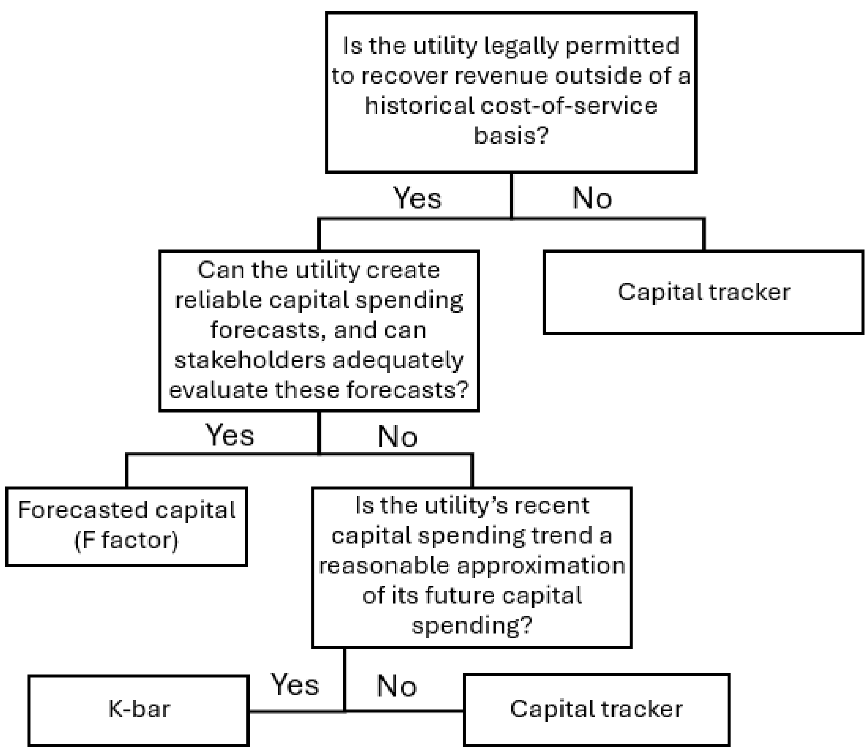
infrastructure. However, capital trackers could also lead to capital over-investment and reduce utilities' incentive to control costs. However, it has the disadvantage of not incentivizing cost containment, which exposes ratepayers to that risk. Furthermore, annual cost-of-service reviews are costly, and run counter to the goals of PBR.

The advantage of the Project-Specific approach is that it recognizes that a cost-of-service is necessary for extraordinary projects whose costs cannot be accurately forecasted, but retains the high-powered incentive structure for the majority of capital spending. The disadvantage of this approach is that it may be insufficient to address capital funding shortfalls more generally, particularly if there is a project-specific materiality threshold that must be reached in order for the utility to apply for project funding, and the utility faces shortfalls on many projects that are beneath this threshold.

K-bar, like the Forecasted Capital approach, has the advantage of retaining the desired cost containment incentives of an effective PBR plan, as the K-bar funding for a given year is determined mechanistically based on investment decisions in the past, as opposed to being tied directly to what is spent in that year. However, K-bar has the disadvantage of being more difficult to understand, and hinges on the assumption that investment decisions in the past are an accurate predictor for investment decisions in the present, which may not hold.

Figure 5.3 presents a flow chart that could be used as a starting point for evaluating what form of capital supplement could work for a given utility. If the utility is not legally permitted to recover capital expenditures prior to placing capital into service, a capital tracker approach may be the only option, even though such an approach has poor cost containment incentives.

**Figure 5.3: Evaluating Capital Supplement Options**



A review of capital treatment across North American PBR plans revealed that the industry has not reached a consensus on capital recovery under PBR. Each approach to capital recovery gives rise to a certain level of complexity, risk, regulatory burden, and incentive pressure. However, the overarching similarity across PBR frameworks is that utilities have been granted means for recovering additional revenues, beyond what might be permitted under the I-X formula, in order to meet capital spending needs.

**Table 5.10: Recommendations for Capital Factors**

| | |
|---|---|
| Capital Factors | *If the Maine IOUs operate under an indexed cap regulatory framework, we recommend that some form of capital supplement be included on an as-needed basis. The capital factor should be company-specific and the costs eligible for capital factor treatment should be clearly defined at the outset of the PBR term. We recommend adopting capital factors that provide cost efficiency incentives, such as a forecasted capital or K-bar approach, when possible.* |

### 5.2.5.7 Reopeners

A fundamental feature of MYRPs is a longer period of time between traditional revenue requirement applications for the utility under the plan. This time between "rebasing" results in a prolonged separation of costs and revenues, providing the utility with enhanced efficiency incentives but also enhanced risk. The I-X formula provides some attrition relief for utilities over the PBR term, but because costs and revenues are separated over the PBR term by design, sufficient cost recovery only persists if the utility experiences stable cost escalation in line with the formula. Since the automatic nature of the I-X formula does not adjust annual revenues for sustained changes in utility costs in the comprehensive manner that rate applications adjust revenues, a utility operating under PBR could potentially experience earnings that are dramatically higher or lower than the amount provided under the I-X formula. To protect against an untenable divergence of costs and collected revenues, PBR plans include "reopeners," or mechanisms that allow for review of the regulated entity's PBR plan during the PBR term and potential relief in the form of adjustments to the PBR plan or exiting the plan completely in the event certain predefined conditions occur.

Reopeners are a common feature of PBR frameworks in North America. It is generally understood that depending on the findings of the regulator, triggering a reopener could result in modifications to a utility's existing PBR plan, termination of the plan, or continuation of the plan. If a problem with the PBR framework is identified, possible remedies to a reopener might include the following:

- Fix design issues – For example, the inflation factor that adjusts rates in Alberta consists of a weighted average of a Fixed Weighted Index (FWI) for labor, and the province's Consumer Price Index (CPI). If the FWI were to deviate dramatically from the price of labor experienced by Alberta distributors, the inflation factor may need to be fixed before the end of the PBR term. Another example would be if a capital supplement were initially critical to providing funding support for necessary investments, but is no longer appropriate for some reason, the reopener could modify this revenue adjustment parameter on a going-forward basis.

- Provide solutions to operational problems – If the utility responds to cost efficiency incentives by reducing costs in a manner that causes concerns for the regulator, targeted solutions like PIMs could be added to provide incentives for the utility to spend efficiently to ensure that service quality does not decline.
- Rebase for unexpected costs – Costs may rise on a broad scale. Likewise, broad-based cost declines may occur. In such cases, rate rebasing may be appropriate and be conducted on a going-forward basis.
- Fix billing errors – If the utility collected revenue that was not correct—for example, because of billing errors, this revenue would be refunded to customers.
- Facilitate an off-ramp – If the PBR framework is found to be fundamentally flawed such that it cannot be modified and continued, an off-ramp allows the utility to leave PBR and transition back to traditional cost-of-service regulation.

**Table 5.11: Recommendations for Reopeners**

| | |
|---|---|
| Reopeners | *If the Maine IOUs operate under an indexed cap regulatory framework or a forecasted MYRP, we recommend that some form of reopener be included. The reopener provision should have a clearly defined trigger and a clear description of how the mechanism would be applied in the event of being triggered.* |

### 5.2.5.8 Earnings Sharing Mechanisms

Earnings Sharing Mechanisms (ESMs) manage the risk of a utility over- or under-earning relative to its allowed ROE. Utilities operating with ESMs share earnings that exceed (or fall short of) a predetermined threshold, either reducing rates for customers in the case of overearning or, depending on the design, providing financial relief to utilities in the event of underearning. As shown in Figure 3.1, above, ESMs are a form of alternative regulation distinct from PBR. This is because ESMs relink the utility's revenues and costs, removing or mitigating cost efficiency incentives. However, ESM are often included in PBR plans as a means of managing risk.

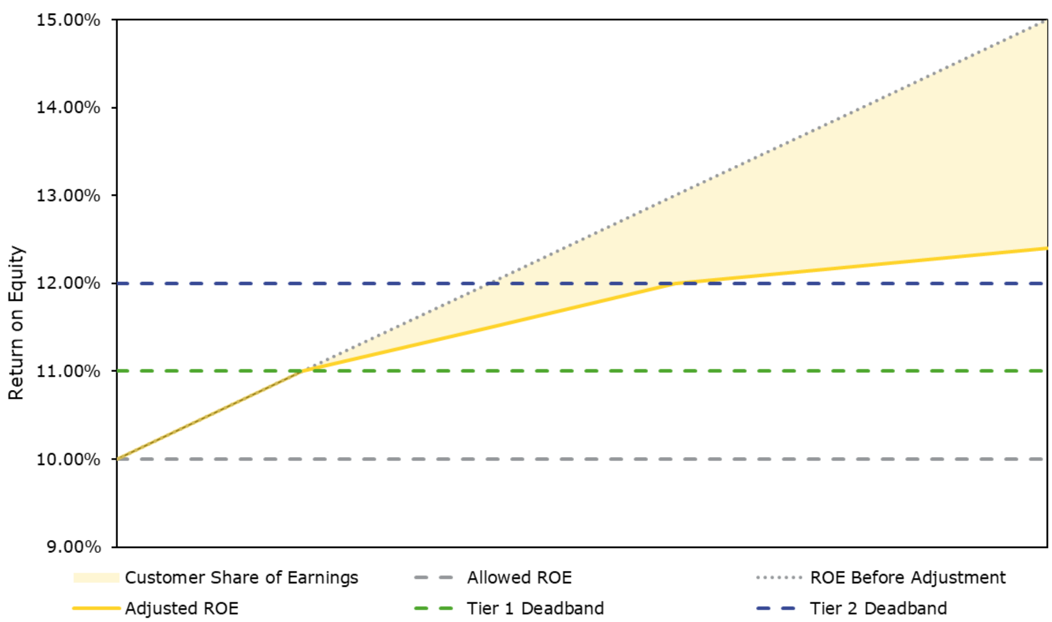
Under both traditional and performance-based regulation, regulators establish a target ROE for the utility through the rate application process. In subsequent years, rates are set according to a revenue requirement that includes this authorized return. Under a symmetrical ESM, if actual earnings exceed or fall short of the target ROE, some proportion of the excess or shortfall is shared between the utility and its customers according to a predetermined formula. This sharing can be structured in tiers, with different sharing percentages applied depending on the magnitude of the deviation of realized earnings from the target or allowed ROE.

A key feature of many ESMs is the use of so-called "deadbands." A deadband is the range around the target ROE within which no sharing occurs. Earnings within the deadband are retained entirely by the utility, insulating it from small fluctuations while maintaining the sharing mechanism for larger deviations. When earnings fall outside the deadband, the sharing arrangement is triggered. If a regulatory framework contained an ESM with no deadband, the utility would operate under pure cost-of-service regulation, with no incentive to find cost efficiencies.

ESMs may have a symmetrical or asymmetrical design. Symmetrical ESMs allow a true-up for both under-and over-earning. Asymmetrical ESMs require the utility to share profits exceeding a predetermined threshold with customers, while bearing full responsibility for any earnings shortfalls. Such a design aims to benefit ratepayers by allowing them to participate in efficiency gains without bearing the risk of earnings shortfalls.

Figure 5.4 provides an illustrative example of how a utility's earnings would change under a two-tier, asymmetric ESM. This example assumes that the utility's allowed ROE is set at 10%. The ESM is structured to have a 100-basis point deadband, such that there no sharing occurs for earnings below an ROE of 11%. If ROE exceeds 11%, the utility shares 50% of its earnings between 11% and 12% ROE and 80% of earnings above 12% ROE.[68]

**Figure 5.4: Two-Tier ESM Over-Earning Example**




[68] In this example the deadband is established around the adjusted ROE and not the ROE before the adjustment. This is due to the fact that first tier adjustments reduce utilities effective ROE.

| **Earnings Sharing Mechanisms Example: Eversource Energy** |
|---|
| As part of their most recent revenue cap plan, Eversource Energy, an electricity distribution utility, proposed a tiered asymmetric ESM, structure as follows:<br><br>• Customers would receive 25% of earnings between 100 and 150 basis points above the authorized ROE.<br>• Customers would receive 50% of earnings between 150 and 200 basis points above the authorized ROE.<br>• Customers would receive 75% of earnings exceeding 200 basis points above the authorized ROE.<br>• No adjustments would be made for earnings below the authorized ROE.<br><br>One advantage of this tiered approach, which allows the utility to retain a larger proportion of its earnings just above the allowed ROE, is to facilitate the enhanced cost efficiency incentives of the revenue cap plan while offering protection to customers in case the utility manages to make very large efficiency gains. However, the Massachusetts Department of Public Utilities approved a different ESM, under which customers would receive 75% of all earnings exceeding 100 basis points above the authorized ROE.[69] |

ESMs present a good example of an alternative regulation tool that is used to adjust the risk-reward balance of a regulatory framework. While the use of an ESM can reduce earnings risk for the utility and protect customers from paying rates that lead to unpalatable utility profits, the reconnection of revenues and costs also reduces the incentive power of a PBR plan. Through an ESM refund mechanism, utility customers may end up with a bigger slice of a smaller pie in the long run.

**Table 5.12: Recommendations for Earnings Sharing Mechanisms**

| | |
|---|---|
| Earnings Sharing Mechanisms | *If the Maine IOUs operate under an indexed cap regulatory framework or a forecasted MYRP, utilities or utility stakeholders may wish to incorporate ESMs. ESMs are not necessary elements of a regulatory framework. However, if ESMs are adopted, we recommend wide deadbands in order to maintain cost efficiency incentives. For example, sharing only after a 200+ basis point deviation from allowed ROE.* |

### 5.2.5.9 Efficiency Carryover Mechanisms (ECMs)

An ECM is a mechanism that allows for a portion of productivity gains to be kept by the utility beyond the end of a PBR term.[70,71] Over the course of a PBR term, the utility has an incentive to find efficiency gains, but rebasing between PBR generations appropriates these gains (and

[69] Massachusetts Department of Public Utilities. *D.P.U. 22-22*. November 30, 2022

[70] Not all PBR frameworks include ECMs. For example, the revenue cap plans currently in effect in Massachusetts and Hawaii do not have defined ECMs. While the current FortisBC PBR plan does not contain an ECM, the BCUC has allowed FortisBC to apply for an ECM under a certain set of criteria.

[71] Mark Lowry, Matt Makos, J Deason, and L Schwartz, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities. GRID Modernization Laboratory Consortium U.S. Department of Energy*. July 2017.

returns them to consumers) with an updated cost-based revenue requirement. This weakens incentives for the utility to identify and implement efficiency gains in the final years of a PBR term. An ECM is designed to combat these adverse incentives.

Currently, ECMs are not widely used in North American PBR plans.[72] However, theory suggests that economic benefits may be fostered by ECMs. If Maine opts to pursue indexed cap PBR, stakeholders should carefully consider possible ECM designs.

**Table 5.13: Recommendations for Efficiency Carryover Mechanisms**

| | |
|---|---|
| Efficiency Carryover Mechanisms | *If the Maine IOUs operate under a MYRP regulatory framework, we recommend consideration of Efficiency Carryover Mechanisms as a way to maintain cost efficiency incentives over rebasing periods.* |

### *5.2.6 Indexed Cap Summary*

The indexed cap form of incentive regulation may provide benefits to customers in the form of slower rate escalation over time relative to more traditional regulatory structures that do not provide such cost efficiency incentives. Given current pressures on utilities as a result of price inflation, price and revenue caps could provide Maine IOUs with a tool to address customer concerns regarding cost control.

As discussed above, price caps and revenue caps differ in a few important ways. Under a price cap, revenues vary with consumption, which may lead to increased risks from a business perspective. Over the course of a Multi-Year Rate Plan, a price cap may lead prices to become misaligned with costs to serve if consumption declines, leading to losses that impede future investment. Conversely, consumption increases (e.g., because of sales volume growth) can lead to returns beyond the conventionally acceptable range set forth by the regulating body if prices are not set equal to unit costs. A revenue cap model, on the other hand, allows the utility to adjust its rates to reflect an indexed level of revenue, rather than prices.

Whether conditions in Maine are better suited to a price cap or revenue cap is an open question. Uncertainty lingers with respect to future electricity usage trends because electrification efforts increase the demand for energy even as conservation reduces the demand for energy. Electrification also drives utility costs, creating cost uncertainties. In the face of this uncertainty, revenue caps may provide stability for utilities over the course of the PBR term. On the other hand, revenue caps may limit the revenue growth required to internally fund the investments required to meet electrification demands. The choice between price and revenue caps depends on various factors, including the specific goals of the regulator, the characteristics of the utility and its service territory, and broader policy objectives such as promoting energy efficiency or renewable energy adoption.

[72] ECM was used in Alberta but was discontinued in their most recent PBR plan (Decision 27388-D01-2023) due to insufficient evidence that it was achieving the intended purpose of reduced incentive to find efficiencies towards the end of the rate plan. Australia currently implements a form of ECM through efficiency benefits sharing scheme and capital expenditure sharing scheme, and New Zealand – through incremental rolling incentive scheme.

Indexed caps also carry risks, such as the potential for reduced service quality if utilities cut costs too aggressively. To mitigate this, regulators often incorporate quality of service standards and PIMs into the MYRP framework. Other risks include revenue deficiencies over the PBR term, which, because of the rate case stay-out agreement, cannot be remedied in the form of a timely rate case filing. Such financial risks can also be mitigated through the inclusion of additional elements in the PBR framework (Z, Y, and K factors).

Table 5.14 summarizes the common components of indexed cap PBR plans.

**Table 5.14: Description of Factors Used in Price and Revenue Caps**

| Factor | Description |
|---|---|
| Inflation | The most recent government numbers for the chosen inflation measure. |
| X Factor | A measure of industry-wide productivity growth. |
| Stretch factor (Customer dividend) | Adjustment applied to the X factor to share efficiency gains between utility and its customers. |
| Z factor (Exogenous cost factor) | Allows rate adjustments for unforeseen, non-controllable events such as natural disasters or major regulatory changes. |
| Y factor | Allows rate adjustments for recurring costs that utilities cannot control such as transmission charges. |
| K factor | Provides revenue support beyond I-X for capital expenditures. |
| Reopeners | Allows for remedying potential problems with the PBR plan before the end of the PBR term. |
| Earnings Sharing Mechanisms | Share earnings that deviate from allowed ROE. Maybe symmetric or asymmetric, with different proportions of sharing and different deadbands. |
| Efficiency Carryover Mechanism | Strengthens PBR incentives across PBR rebasing periods. |

Successful implementation of price or revenue caps can improve the operational efficiency of utilities and generate savings for customers.

Due to the lumpiness of capital, utilities generally require additional revenue support for capital spending. In addition, each utility operates within a different stage of their capital investment cycle, which means some utilities might benefit, while others may struggle, from the capital input trends reflected in the industry productivity factor.[73] While some of the challenges of applying price and revenue caps can be addressed through the exclusion of highly variable cost components from index cap, such exclusions would also risk reducing the benefits that could be derived from an indexed cap approach.

[73] This can be illustrated with a simple example: if the companies that are included in industry productivity calculation have recently undergone heavy capital investments, the estimated X factor would be lower and would benefit companies that are not pursuing any major capital investments in the near future.

**Table 5.15: Recommendations for Indexed Caps in Maine**

| | |
|---|---|
| Indexed Caps | *We encourage the Maine IOUs to propose, and the Maine PUC to accept, indexed cap plans rooted in the I-X formula.* |

## *5.2.7 Real World Indexed Cap Examples*

To assist with conveying how indexed caps work in the real world, we present three examples: a price cap from Alberta, Canada, a revenue cap from Hawaii, and a hybrid revenue cap from Massachusetts. These jurisdictions have markedly different characteristics. Alberta's PBR framework regulates all distribution-only utilities in the province with the same I-X formula, wherein each utility operates within a landlocked, meshed transmission grid. In Massachusetts, unlike in Alberta, distribution utilities choose operate under a customized revenue cap. The Hawaiian utilities are vertically integrated and operate on islands.

Alberta provides a price cap model that has been refined over multiple PBR iterations. The Massachusetts example demonstrates how capital may be separated from operations and maintenance costs.

### 5.2.7.1 Price Cap Example: Alberta Electric Distribution Utilities

In 2023 Alberta Utilities Commission (AUC) approved its third generation PBR (PBR3) plan for the 2024 to 2028 period, which maintains price cap regulation for electric distribution utilities. Alberta utilities' allowed change in prices is described by the following formula:

$$\%\Delta P = (I - X) + Y + Z + K^1 + K^2 \qquad (5.2)$$

Where:

*%ΔP = allowed change in capped price*
*I = inflation factor*
*X = productivity factor*
*Y = recurring flow through items, collected through Y factor rate adjustments*
*Z = one-time exogenous adjustments*
*$K^1$ = Type 1 capital recovered through capital trackers*
*$K^2$ = Type 2 capital recovered through K-bar*

The X factor is determined based on the results of total factor productivity studies for the electric distribution industry and is further adjusted by a stretch factor.[74] Mechanically, the stretch factor increases the X factor (which reduces the allowed price increases).

AUC has also established asymmetric two-tiered Earnings Sharing Mechanism:

- For earnings between 200 and 400 basis points above the approved return on equity, utilities retain 60% of the excess.

[74] See Jeffrey I. Bernstein and David E.M. Sappington. *Setting the X Factor in Price-Cap Regulation Plans*". *Journal of Regulatory Economics, Vol. 16*. 1999. p. 9.

- For earnings exceeding 400 basis points above the approved return on equity, utilities retain 20% of the excess.

#### 5.2.7.2 Revenue Cap Example: Hawaiian Electric Company (HECO)

The Hawaiian Electric Company operates under a five-year revenue cap plan, based on the following formula:

$$Revenue_t = Revenue_{t-1} * (1 + I - X - CD) + EPRM + Z \quad (5.3)$$

Where:

*$Revenue_t$ = allowed revenue in year t*
*I = inflation, (equal to GDP-PI)*
*X = productivity index (set equal to zero percent)*
*CD = consumer dividend (set equal to 0.22 percent)*
*EPRM = costs allowed to be recovered under the Exceptional Projects Recovery Mechanism*
*Z = costs associated with exogenous, one-time events*

The formula adjusts revenues each year by the percentage change in GDP-PI (the Gross Domestic Product Price Index) minus a pre-determined stretch factor.[75] Each year, depending on circumstances, the utility's allowed revenue may be adjusted by several additional components, including cost trackers, a Z factor, PIMs, and a capital recovery mechanism.

The Hawaiian utilities have cost trackers that allow for the recovery of costs pertaining to fuel and purchased power, pensions, demand-side management, renewable energy infrastructure program. These costs are recovered outside of the allowed revenue that is adjusted by the inflation-based revenue cap. The Z factor provides the utility with an opportunity to review and recover prudently incurred costs that address events beyond the control of the utility.[76]

The PBR framework also contains a provision for additional revenue related to capital expenditures. In particular, the Exceptional Project Recovery Mechanism (EPRM) is a mechanism that allows the utility to file for cost recovery of projects that meet certain criteria. It provides recovery of allowed revenues for the net costs of these approved "Eligible Projects" placed in service during HECO's five-year revenue cap period, provided that cost recovery is not already covered by another effective recovery mechanism.[77] Eligible Projects include infrastructure necessary to connect renewable energy projects, projects that encourage clean energy choices or conservation, utility scale generation and storage, grid modernization, and other similar projects.

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[75] Although the PUC referred to HECO's revenue cap as an "I-X" revenue cap because an X factor was considered, the X factor was arbitrarily set to equal zero in the final decision. For this reason, the Hawaii revenue cap is not truly an "I-X" revenue cap, as it does not incorporate industry productivity.

[76] HECO's exogenous costs must exceed a threshold of $4 million to be eligible for Z factor cost recovery. This is equivalent to 0.14% of the company's total allowed revenue.

[77] Hawaii Public Utilities Commission. *In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval to Commit Funds in Excess of $2,500,000 (excluding customer contributions) for the PZ.005125 – Kahe-Waiau 138 kV Undergrounding Project and to Recover Costs through the Exceptional Project Recovery Mechanism. Decision and Order No. 38451 Docket No. 2021-0086*. p. 62.

### 5.2.7.3 Hybrid Revenue Cap Example: National Grid

Massachusetts Electric Company and Nantucket Electric Company, each doing business as National Grid, operated under a total revenue cap formula from 2019 to 2024, similar to the cap adopted by the Hawaiian Electric Company. However, beginning in 2025, the revenue cap was modified to treat O&M and capital expenses separately; an anticipated surge in necessary capital investment, driven in large part by the Electric Sector Modernization Plan for Massachusetts, was expected to leave the company with insufficient revenue during the 2025-2029 period. To resolve this issue, the company proposed bifurcating its revenue requirement into revenue associated with O&M expenses and a capital revenue requirement. The former would be escalated by an index formula each year, while the latter would be recovered from annual capital revenue requirement filings. This proposal was accepted by the Department of Public Utilities in Massachusetts in 2024, with the O&M revenue requirement escalated using the following formula:

$$OM\ Revenue_t = OM\ Revenue_{t-1} * (1 + I - X - CD) + Y + Z \tag{5.4}$$

Where:

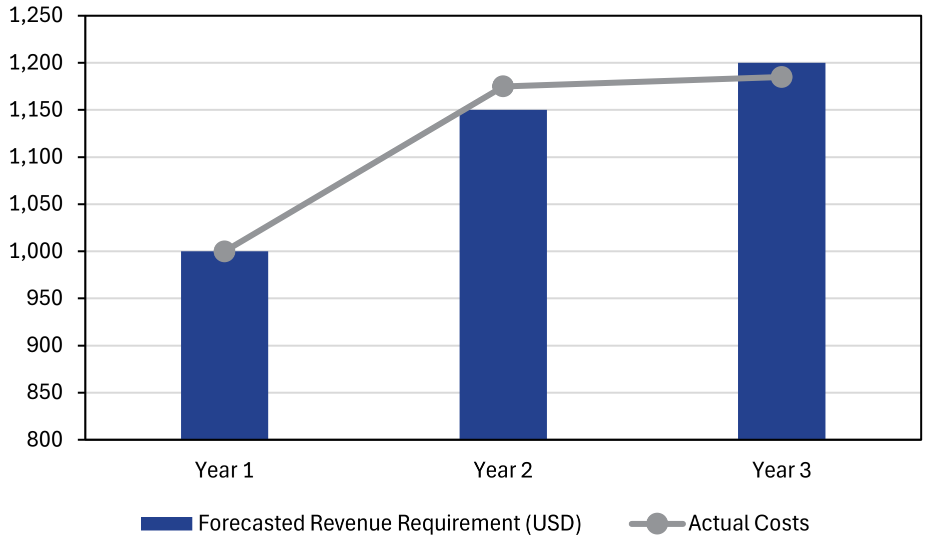
*OM Revenue*$_t$ *= O&M revenue requirement in year t*
*I = inflation, (equal to a weighted average of a regional employee cost index and the producer price index for electric utilities)*
*X = partial productivity index (set equal to 0.21 percent)*
*CD = consumer dividend (set equal to 0.4 percent)*
*Y = incremental operating expenses arising from increased capital expenditures*
*Z = costs associated with exogenous, one-time events*

## 5.3 Forecasted Multi-Year Rate Plans

A forecasted approach offers an alternative to the indexed cap MYRP. Utilities might implement a forecasted MYRP in a number of different ways, but the key differentiating feature of forecasted MYRPs relative to indexed caps is that whereas price caps and revenue caps rely on industry average adjustments that are exogenous to the company, a forecasted MYRP relies on the company's own forecasts of its revenue requirement over a period of time. The forecasted MYRP approach establishes the utility's revenue requirement each year of the PBR term at the initial plan filing. These forecasts typically include estimates of future operating expenses, capital investments, depreciation, taxes, and allowed rate of return, as well as projected sales and number of customers served.

Figure 5.5 depicts a prototypical three-year forecasted MYRP. Under this plan, the utility's actual costs may vary year-to-year relative to its forecasted revenue. In Year 1, realized costs are closely aligned with the forecasted revenue requirement. This is expected because forecasts are generally more accurate for costs incurred in the near future than for those further in the future. In Year 2, actual costs exceed the forecasted revenue requirement. In this case, the utility will need to manage under a revenue shortfall, as the revenue requirement cannot be adjusted during the MYRP term. In the final year of the MYRP, the example utility's forecasted revenue exceeds its actual costs. In this case, the utility is able to keep its profits.

**Figure 5.5: Illustrative Example of Forecasted MYRP**




## *5.3.1 Advantages of the Forecasted MYRPs*

Forecasted MYRPs provide more oversight and control over the utility's revenues during the PBR term, both for the utility and for the regulator, relative to indexed caps. One key advantage of the forecasted revenues approach is that it can provide a more accurate reflection of the utility's expected costs and market conditions compared to indexing caps. This can be particularly beneficial in periods of significant change, such as when major infrastructure investments are planned or when the utility sector is undergoing substantial transformation. A utility facing cost growth substantially different from the rest of the industry might therefore find forecasted MYRPs feasible, even when indexed caps are not workable.

## *5.3.2 Drawbacks and Risks to Forecasted MYRPs*

However, there are risks and potential drawbacks. One drawback is that the forecasting process may involve extensive negotiations, evaluations, and input regarding the projected revenue requirement from various stakeholders, including consumer advocates and industry experts. This process may be more expensive and time consuming than a traditional cost-of-service rate case. However, as with indexed caps, the initial administrative costs would be outweighed by the reduction in rate case frequency and cost efficiency gains under a well-designed plan.

A risk with forecasted MYRPs is that, typically, under a forecasted MYRP, the company may only collect the forecasted revenues—regardless of the costs incurred. While this risk imposes some cost efficiency incentives on the firm, allowing it to earn profits for better-than-expected cost management, the firm could incur losses if its costs exceed allowed revenues. Similarly, companies may seek to benefit from information asymmetry by inflating their forecasted revenue requirement in order to mitigate risk or improve profits. To address concerns that costs may diverge from allowed revenues over the PBR term, regulators often incorporate mechanisms to share the risk of forecast errors between the utility and its customers. For example, in Great Britain, utilities operating under the "Revenue using Incentives to deliver Innovation and Outputs" (RIIO) framework pay a forecasting penalty that increases as actual costs deviate from the forecast.[78] Another approach might include earnings sharing provisions that require the utility to return a portion of any excess earnings to customers if actual costs turn out to be lower than forecasted.[79] Similarly, some plans may include reopener clauses that allow for rate adjustments if actual costs deviate significantly from the forecast.

Another risk, which also exists under indexed cap PBR, is that cost cutting may occur not because of gains in efficiency, but rather, at the expense of service quality. To protect consumers from the utility cutting spending at the expense of service quality or planned capital expenditures, the regulator may introduce PIMs or impose rules requiring capital to be placed into service before related revenues can be collected by the company.

**A Note on Future Test Years**

A forward-looking test period can be used to set a utility's revenue requirement on the basis of projected data for a 12-month period beginning no later than 24 months after the date on which the utility petitions the commission for a change in its rates and charges. This form of cost-of-service regulation using projected data has qualities that overlap with forecasted MYRPs. Both require forecasted cost information, and both can be used to provide a timely alignment of rates with costs.

As with any regulatory construct, the likelihood of success for forecasted MYRPs depends on the details. The forecast approach also may result in higher or lower cost efficiency incentives depending on the plan design. If the utility can influence the forecast to be overly generous, it may reduce the pressure to cut costs. Conversely, if the forecast is too stringent, it could put undue financial pressure on the utility, potentially compromising service quality or necessary investments.

The forecasted revenues approach can be more complex and resource-intensive than other MYRP methods, requiring significant regulatory oversight and expertise. However, when implemented effectively, it can provide a balanced framework that aligns utility incentives with regulatory objectives while accounting for the specific circumstances and challenges facing the utility over the plan period. Table 5.16 provides our recommendations with regard to forecasted MYRPs.

[78] Decision – RIIO-ED2 Final Determinations Finance Annex, p. 132.

[79] While earnings sharing mechanisms may be effective in addressing forecast errors, they reduce the incentive for utilities to efficiently manage their expenditures.

**Table 5.16: Recommendations for Forecasted MYRPs in Maine**

| | |
|---|---|
| Forecasted MYRPs | *We recommend Maine IOUs continue to be permitted to voluntarily file forecasted MYRPs. We further recommend consideration of MYRP terms longer than the two-year plan currently applied to CMP (for example, three or four years). We note that indexed cap plans may offer more simplicity and better cost efficiency incentives, depending on the plan design.*<br><br>*If three- or four-year forecasted MYRPs are adopted, these plans may include additional elements discussed in Table 8.4. For example, exogenous cost factors (Z and Y factors) may be included, as well as reopener provisions.* |

### *5.3.3 Real World Forecasted MYRP Example: Duke Energy Carolinas*

On October 13, 2021, a bill authorizing PBR for electric utilities was signed into law by the Governor of North Carolina.[80] This change permits utilities in North Carolina to submit PBR applications as part of their general rate case. Such applications could include revenue decoupling mechanisms, PIMs, earnings sharing mechanisms, and forecasted MYRPs.

Duke Energy Carolinas' (DEC) most recent general rate case included a PBR plan with many of these elements. DEC proposed and currently operates under a three-year forecasted MYRP with an asymmetric ESM that distributes all earnings excess of 50 basis points above the authorized return on equity to customers. The plan also contains a reopener, which states that if DEC's weather-normalized earnings fall 50 basis points below the authorized rate of return on equity, DEC may file a rate case, thereby leaving the MYRP. Revenue increases during the MYRP are determined based on forecasted capital spending throughout the rate period and are capped at 4% of the first-year revenue requirement, excluding capital spending projects placed in service during the first rate year.

Arguably, North Carolina's approach to MYRPs offers some cost containment incentives. The reopener and ESM limits the benefits utilities can derive from efficient cost reductions. However, the plan may also facilitate other benefits, such as less frequent rate applications and timely cost recovery.

## 5.4 Formula Rates

We include formula rates in this discussion for the sake of completeness as an alternative form of regulation, but formula rate plans are not considered to be a form of PBR. Formula rates are used by many electricity transmission companies that file rates with the Federal Energy Regulatory Commission, as well as some retail utilities in the southeastern United States.

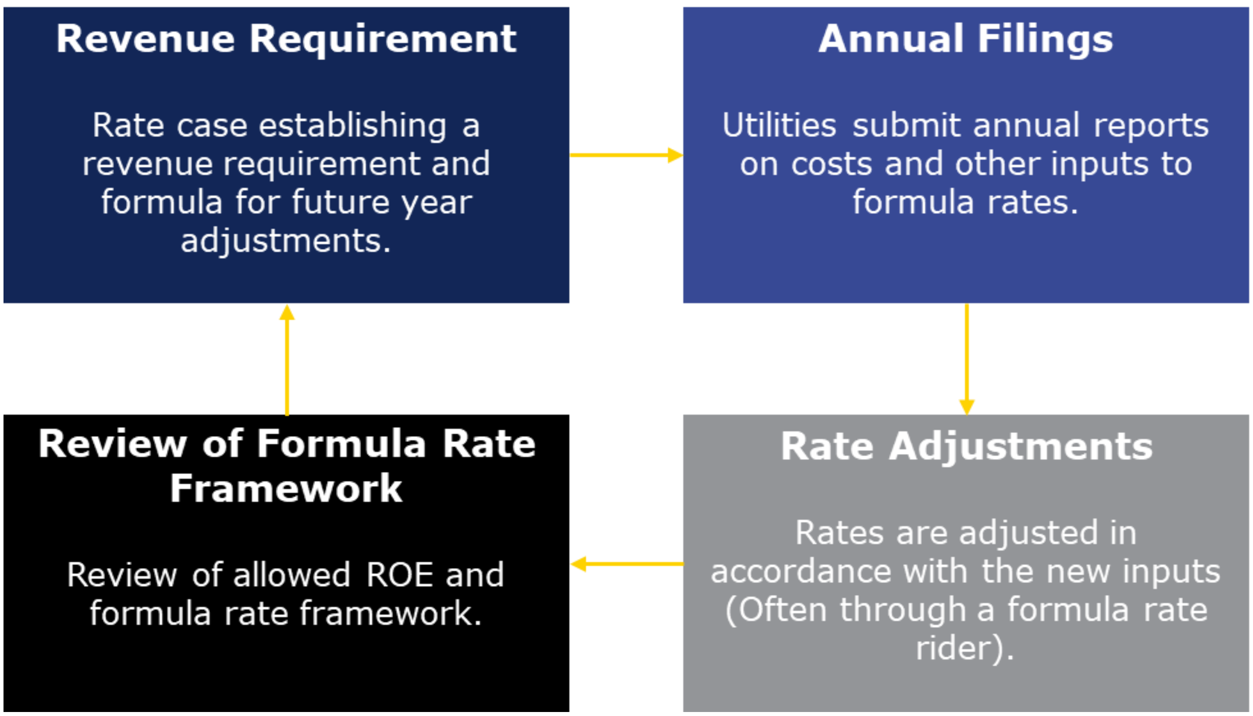
Formula rate plans establish a formula based on company earnings information to automatically adjust rates, typically on an annual basis. Because of the name, formula rates might be confused

[80] *G.S. 62-133.16*

with indexed cap plans, which also rely on a formula. However, the two forms of regulation are very different. Unlike indexed caps, formula rate plans set prices based on company specific data rather than industry-wide information. This means that rates are set on a cost-to-serve basis and do not have the incentive properties of indexed caps. In fact, because of the low efficiency incentives associated with formula rate plans, such plans are not considered to be a PBR tool.

Figure 5.6 provides a simplified overview of how formula rates are established, reviewed and updated. The specifics of formula rates differ between jurisdictions, but the formula rates are generally established for multiple years and require annual filings by the utilities to report their costs and earnings. At the end of the pre-determined formula rate period, the formula rate framework is reviewed and updated.

**Figure 5.6: Simplified Formula Rate Application Process**




### *5.4.1 Advantages of Formula Rate Plans*

The advantage of formula rate plans is that they are designed to provide a transparent and predictable way to update rates without the need for frequent, full-scale rate cases. The formula usually incorporates various components of the utility's costs, such as operating expenses, capital investments, return on equity, and sometimes performance metrics, as well as allowed rate of return. Each component of the formula is clearly defined and may be subject to specific rules or limits. For example, the allowed rate of return might be adjusted annually based on changes in financial market conditions. Formula rate plans also have the advantage of providing timely cost recovery for utilities. As actual costs change, rates can be adjusted relatively quickly, reducing regulatory lag and potentially lowering the utility's financial risk.

### 5.4.2 Drawbacks of Formula Rate Plans

One of primary drawbacks of formula rates is that they often allow utilities to pass increased costs directly to customers. This mechanism reduces the utility's incentive to pursue cost reductions or efficiency improvements. It also may make it more difficult to assess projects that are recovered through rates between rate applications. As such, formula rate plans require careful design and ongoing monitoring to ensure they serve the interests of both the utility and its customers throughout the MYRP period.

Table 5.17 provides our recommendations regarding formula rate plans.

**Table 5.17: Recommendations for Formula Rate Plans in Maine**

| | |
|---|---|
| Formula Rate Plans | *We do not currently recommend that Maine IOUs pursue formula rate plans. However, if IOUs face major, lumpy investments and the frequency of rate cases becomes a problem, this is an option that could be considered.* |

### 5.4.3 Real World Example of a Formula Rate Plan: Entergy Louisiana

Entergy Louisiana's rates have been set through a Formula Rate Plan (FRP) since 1995. In Entergy Louisiana's most recent rate case, the formula rate plan has been extended for 2024-2026 period.[81]

Entergy Louisiana operates their formula rates through a FRP Rider. The FRP regulates electric rates by establishing an approved Evaluation Period Cost of Equity (EPCOE) and then requiring prospective rate changes if Entergy Louisiana's test year operating revenues produce an earned return on equity either higher or lower than the approved EPCOE plus or minus a 40-basis point earnings bandwidth (deadband). For a given year of the FRP, if the Company's earned return on equity falls outside the deadband, the FRP will adjust rates to the edge of the deadband.

Each year Entergy Louisiana is required file an FRP evaluation report, which is based on Entergy Louisiana's actual earnings for the prior 12 months. Any revenue adjustments and changes to rates through the FRP rider are reflected in the evaluation report.

There are several categories of costs that the current FRP allows Entergy Louisiana to recover outside the mechanism described above. Some exceptions include recovery of certain investments in capacity and transmission, extraordinary costs; and certain Midcontinent Independent System Operator (MISO) related costs and revenues.

## 5.5 MYRP Summary

Utility MYRPs consist of several categories: indexed caps, forecast-based rates, and formula rates, though hybrid approaches combining elements of these categories are also common. A hybrid MYRP might blend indexed caps with forecast adjustments or incorporate other forms of

[81] Louisiana Public Service Commission. *Order U-36959*. September 13, 2024.

cost-of-service information, like capital trackers. Because the specific details of each plan vary between jurisdictions, and even between utilities within jurisdictions, no two MYRPs are exactly alike. These differences arise from different utility spending plans, industrial organization (e.g., vertically integrated vs. distribution-only), regulatory objectives, risk tolerance, and precedent.

The design of a MYRP has implications for utility incentives. Whereas indexed caps generally provide enhanced cost efficiency incentives, formula rates have relatively low-cost efficiency incentives. Improved incentives may correspond to higher risks, or, for utilities with particularly lumpy capital investment, a pure indexed approach may simply not be workable given the utility's spending plan. A well-designed MYRP must balance considerations of cost efficiency with feasibility. If a proposed MYRP framework is out of line with the spending forecast of the utility, it will not provide benefits to customers in the long run, no matter how strong the plan's theoretical incentives might be.

Throughout this section, we have reviewed the benefits and challenges of different forms of MYRPs. Each approach presents a different balance of priorities. Table 5.18 provides a summary of these benefits and challenges.

**Table 5.18: Benefits and Challenges of Approaches to MYRPs**

| Approach | Benefits | Challenges |
|---|---|---|
| **Price Caps** | • Provides an annual rate adjustment equal to the rate of inflation minus industry productivity over the MYRP term<br>• Utility can increase revenue and profits through sales growth<br>• Provides cost efficiency incentives | • May result in intervenor resistance to automatic rate increases<br>• Does not protect the utility against sales declines |
| **Revenue Cap + Decoupling** | • Provides an annual rate adjustment equal to the rate of inflation minus industry productivity, plus customer count growth over the MYRP term<br>• Protects utility against sales declines<br>• Provides cost efficiency incentives | • May result in intervenor resistance to automatic revenue increases<br>• Does not allow for revenue increases beyond the I-X+G adjustment, even if sales increases occur |
| **Forecasted MYRP** | • Provides utility with opportunity to request revenues according to expected costs<br>• Relatively straightforward to implement<br>• Protects utility against sales declines | • Intervenor resistance to automatic revenue increases<br>• Requires more regulatory scrutiny over spending forecasts<br>• Strength of cost efficiency incentives not well established in economics literature |
| **Formula Rates** | • Reduces rate application frequency<br>• Aims to keep revenues and costs closely aligned | • Has the lowest cost efficiency incentives (and is not considered to be PBR)<br>• May face criticism related to the evaluation of projects between rate cases. |

The regulated electric utilities in Maine already have the opportunity to file MYRPs in the form of an Alternative Rate Plan. Other jurisdictions, like those in Canada, Australia, and Great Britain, have developed standardized MYRP models that all utilities within the jurisdiction must follow. However, these jurisdictions generally contain many more distribution utilities than Maine.

The MPUC could consider creating a set of standard practices that CMP and Versant Power must follow if they file a MYRP. This could be a highly structured, detailed set of rules, or a high-level set of principles.

As explained in **Error! Not a valid bookmark self-reference.**, we recommend that the utilities in Maine follow an indexed cap framework—either a price cap or a revenue cap, though forecasted MRYPs would also be a reasonable approach. The IOUs would file these rate applications as part of the Alternative Rate Plan option that is already in effect.

**Table 5.19: Recommendations for MYRPs**

| | |
|---|---|
| Recommendations for MYRPs in Maine | *Maine IOUs are already permitted to file MYRPs as an alternative rate plan. To provide cost efficiency incentives to the utilities, we encourage the adoption of either forecasted or indexed cap MYRPs.*<br><br>*Furthermore, we note that, as "lines-only" utilities, IOUs in Maine may be well-suited for indexed cap (price cap, revenue cap, or hybrid) PBR frameworks, as these plans provide cost efficiency incentives that may improve customer affordability. We therefore encourage the state's IOUs to voluntarily propose indexed cap MYRPs, and we encourage the Maine PUC to accept well-designed indexed cap plans.* |

# 6 OTHER TOOLS IN ALTERNATIVE REGULATION

## 6.1 Capital Trackers or Project Pre-Approval

Cost of service regulation with regulatory lag can create issues for timely cost recovery, particularly for large capital projects. Under traditional regulation, rate cases set rates according to a utility's embedded costs, but costs associated with new projects are not recovered in base rates until the conclusion of the next rate case. This lack of timely cost recovery can cause hesitation by utilities in making large capital investments. To provide more stable and timely cost recovery, capital trackers that recover revenue on an annual basis have been implemented in many jurisdictions.

Capital trackers can be applied to utilities operating under MYRPs, or by utilities regulated by traditional rate case regulation. As stated in Section 5.2.5, capital trackers can reduce the regulatory lag for utilities, and increase the willingness of utilities to invest in critical infrastructure. However, capital trackers could also lead to capital over-investment and reduce utilities' incentive to control costs.

## 6.2 Totex

Under the "totex" ratemaking approach, distributors obtain a return on total expenditures (totex), which contains elements of both capital spending (capex) and operating spending (opex). The totex approach to setting returns differs from the traditional approach to setting utility returns, in which only capitalized expenditures earn a return. The totex approach attempts to counter-balance a perceived incentive for utilities to exhibit a capital bias in spending, since capital spending accompanies an allowed return. Under the totex ratemaking approach in Great Britain, utility totex is divided into "Slow Money" and "Fast Money" at a predetermined capitalization rate. "Slow Money" is capitalized and over time, incorporated into the annual depreciation expense, like capex in the traditional approach. The remainder of totex spending, called "Fast Money", is incorporated into the allowed revenue as an expense, like opex in the traditional approach.[82]

The totex approach can also be coupled with an earning sharing mechanism to encourage cost efficiency. In Great Britain, the regulator, Ofgem, set ex ante totex allowances for the utility during the term of each utility's Multi-Year Rate Plan. A sharing factor called the Totex Incentive Mechanism determines companies' exposure to under or overspends compared to the totex allowances. Totex ratemaking approach has been adopted in Great Britain and Italy as a component of utility regulation. Some jurisdictions (e.g., New York and Hawaii) in the US have considered adopting a totex approach, but it is not currently in use in the United States.

## 6.3 Revenue Decoupling

Revenue decoupling is a regulatory mechanism used in the electric utility industry to separate a utility's revenue from its sales volume. Traditionally, utility profits were directly tied to the amount of electricity sold, creating an inherent incentive for utilities to promote increased energy

[82] "RIIO-ED2 Final Determinations Core Methodology Document," Ofgem, 30 November 2022.

consumption. Decoupling breaks this link, allowing utilities to recover their fixed costs and earn a fair return on investment regardless of fluctuations in electricity sales.

The primary purpose of decoupling is to align the financial interests of utilities with broader energy efficiency and conservation goals. By removing the disincentive to promote energy efficiency, decoupling allows utilities to support and implement energy-saving measures without fear of revenue loss. This regulatory approach aims to create a more sustainable and environmentally friendly energy sector while ensuring the financial stability of utility companies.

Decoupling typically involves setting a revenue target for the utility based on its fixed costs and authorized rate of return. If actual revenues fall short of this target due to reduced energy consumption, the utility is allowed to adjust rates to make up the difference. Conversely, if revenues exceed the target, rates are adjusted downward to return the excess to customers. This mechanism helps to stabilize utility revenues and reduces the financial risk associated with fluctuations in energy demand, while also protecting consumers from potential over-charging.[83]

**Is Revenue Decoupling a Form of PBR?**

Revenue decoupling mechanisms could be classified as a form of PBR, but this is not universally accepted. If PBR entails emulating the competitive market outcome correcting for any market failures, then revenue decoupling mechanisms can be used to achieve this objective. (For instance, the regulator might worry customer consumption deviates from the social optimum because customers don't internalize the negative externality of environmental impacts.) In any case, revenue decoupling mechanisms are often included in PBR frameworks, so we include a discussion here for completeness.

### *6.3.1 Revenue Decoupling in Practice*

Revenue decoupling mechanisms can be implemented in various ways, tailored to specific regulatory environments and utility structures. These approaches aim to balance the needs of utilities, consumers, and regulatory objectives. One common method allows utilities to adjust rates each year based on the total revenue requirement established during the rate case, such that sales volumes ultimately do not affect realized revenue. This approach ensures that the utility can recover its fixed costs regardless of sales, which may fluctuate as a result of exogenous factors like weather. An alternative approach is revenue-per-customer decoupling.

Regulators may also choose to apply decoupling selectively to certain cost categories. For instance, decoupling may be applied to distribution costs while excluding fuel costs. This selective application recognizes that some costs are more volatile or directly tied to consumption than others, allowing for a more nuanced regulatory approach. Regulators may also establish a cap on rate increases from revenue adjustments. When caps are applied, some regulators may allow excess unrecovered amounts to be carried forward to future periods, while others may not. These variations allow regulators to fine-tune the balance between utility financial stability, consumer protection, and energy efficiency incentives.

[83] It is common for regulators to set a cap to limit price changes from decoupling within a given year to minimize fluctuations.

Figure 6.1 shows adoption of revenue decoupling for gas and electric utilities across the United States. Yellow regions indicate revenue decoupling for both gas and electric utilities, while grey indicates no revenue decoupling is in effect.

**Figure 6.1: Revenue Decoupling in the United States[84]**

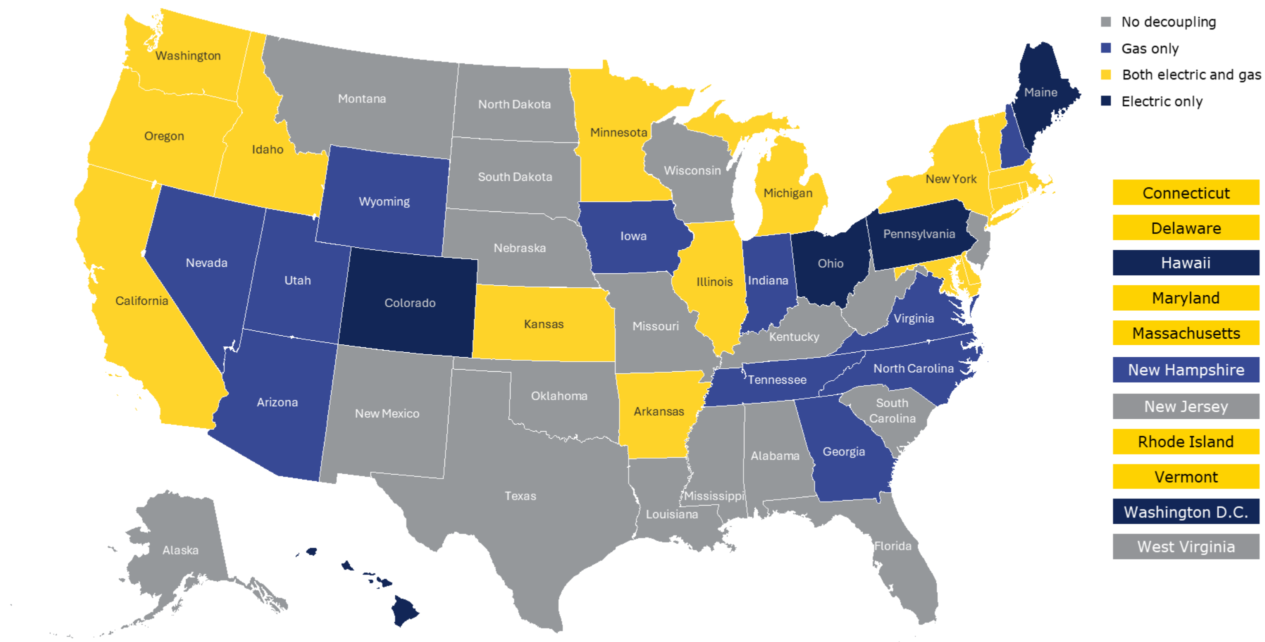



Table 6.1 provides a summary of the advantages and challenges of revenue decoupling. Revenue decoupling was originally designed to remove the disincentive to promote energy conservation by allowing a utility to collect its revenue requirement even if sales volumes decline. Additional benefits include revenue stability and the possibility of less frequent rate cases. Challenges include rate volatility, as customer rates must be adjusted each year as prior year sales volumes fluctuate.

[84] Data for this figure from "Performance-Based Regulation: Harmonizing Electric Utility Priorities and State Policy," by Daniel Shea, *National Conference of State Legislatures*, April 2023.

**Table 6.1: Advantages and Challenges of Revenue Decoupling**

| ADVANTAGES | CHALLENGES |
| --- | --- |
| **Energy Efficiency**<br>• Removes disincentive to promote energy conservation.<br>**Reduced Frequency of Rate Cases**<br>• In changing sales environments utilities would be able to recover<br>**Revenue Stability for Utilities**<br>• Decoupling reduces utility's reliability on sales volumes. | **Rate Volatility**<br>• With annual decoupling adjustments rates are likely to change between rate cases<br>**Complexity**<br>• Decoupling can make utility rates and regulation more complex, potentially reducing transparency. |

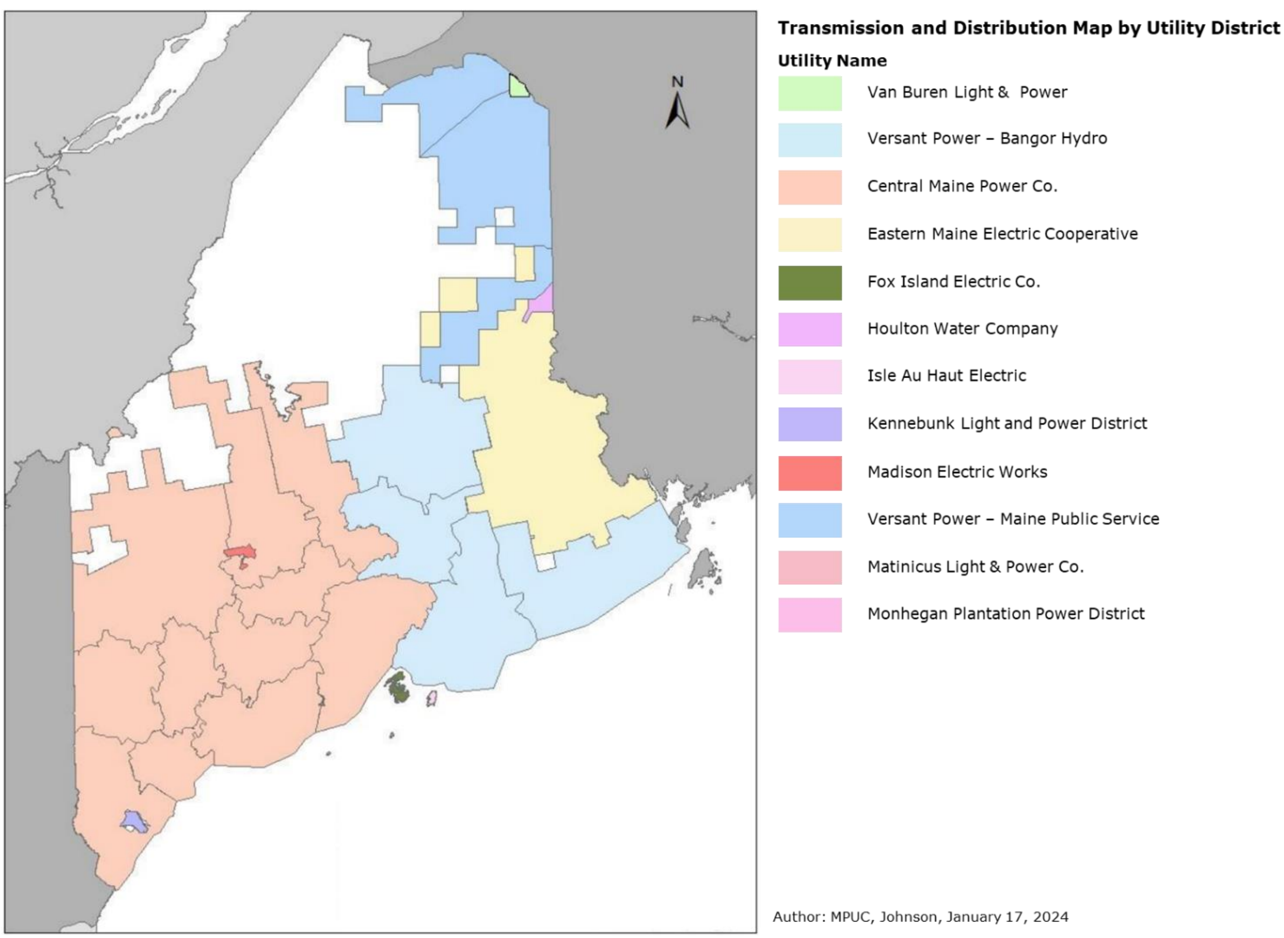
# 7 MAINE RATEMAKING FRAMEWORK

The state of Maine contains two investor-owned distribution electric utilities: Central Maine Power Company (CMP) and Versant Power —formerly Emera. Versant Power's service territory consists of two distinct districts:

- Bangor Hydro District; and
- Maine Public District.

CMP serves 78% of state's residential load, while Versant Power – Bangor Hydro District serves 13.9% and Versant Power – Maine Public District serves 4.1%.[85] The remaining load is served by cooperatives and municipal-owned utilities, collectively known as Consumer Owned Utilities. Electricity generation is not regulated by the MPUC, and electricity is sold in the New England wholesale market administered by the Independent System Operator of New England (ISO-NE). The wholesale market is different for Northern Maine. There, the electric grid is not connected to the New England grid except by going through New Brunswick, and the Northern Maine Independent System Administrator manages reliability.[86]

**Figure 7.1: Transmission and Distribution Map by Utility District**[87]




[85] Maine Public Utilities Commission. *Residential Electric Rates.*
[86] Maine Office of Public Advocate. *Wholesale Electricity Market.*
[87] Maine Public Utilities Commission. *2024 Annual Report*. February 1, 2025.

## 7.1 Industry Overview

In 2000, the Restructuring Act (35-A MRSA, ch. 32) removed Maine's electric utilities from the generation business and required them to sell their various generation assets. The transmission and distribution utilities CMP and Versant Power remain fully regulated by the MPUC. The generation portion of the industry operates in the competitive supply market, and is therefore not regulated by the Commission.[88]

Table 7.1 presents summary information about the state's electricity sector. The state's utilities operate within the ISO New England transmission territory.

**Table 7.1: Summary of Maine Electricity Sector**

| Regulatory Characteristics | |
|---|---|
| Regulated Utilities | 2 IOUs |
| Ratemaking regulator | Maine Public Utilities Commission |
| Transmission Operator | ISO-NE |
| **Alternative Regulation Elements** | |
| Cost Trackers | Yes |
| Revenue Decoupling | Yes |
| Revenue/Price Cap | No[91] |
| Formula Rates | No |
| PIMs | Yes |
| Earnings Sharing Mechanisms | Yes |

| Fuel Mix[89] | | | |
|---|---|---|---|
| Gas | 60.5% | Wind | 4.8% |
| Hydro | 10.2% | Nuclear | 3.5% |
| Oil | 8.9% | Solar | 2.1% |
| Biomass | 8.0% | Other | 2% |

| Energy Sector Facts[90] | |
|---|---|
| Total Installed Capacity | 5,252 MW |
| Total Generation | 12.512 GWh |
| Average Retail Electricity Price | 20.84 cent/kWh |
| Electric Vehicles[92] | 7,377 |
| Battery Storage Capacity[93] | 63.1 MW[94] |

Electricity service in Maine is made up of two parts: supply and delivery (distribution). The price for the supply portion is set within the context of the ISO-NE wholesale market.[95,96] Delivery, on the other hand, is provided by the state's regulated distribution utilities. The regulated rate for delivery consists of four different elements: a transmission charge, a distribution charge, stranded costs (Public Policy Charge), and a conservation charge.[97]

88 Maine Office of the Public Advocate. *Frequently Asked Questions.*

89 Maine Public Utilities Commission, *Residential and Small Non-Residential Standard Offer Service: Consumer Information About Your Electricity* Supply, April 2024.

90 U.S. Energy Information Administration. *Maine State Electricity Profile.* November 6, 2024

91 Central Maine Power operated under an alternative price plan that was discontinued in 2014.

92 Only all-electric vehicles are included. Plug-in hybrid electric vehicles are not included. (Source: U.S. Department of Energy. *Electric Vehicle Registrations by State*).

93 The capacity refers to total deployed capacity at the end of June 2024.

94 State of Maine Governor's Energy Office, *Energy Storage.*

95 Maine Office of the Public Advocate. *Electricity Supply Options.*

96 Maine Office of the Public Advocate. *Electricity Service in Maine.*

97 *Ibid.*

***Stranded Costs (Public Policy Charge)***

Prior the year 2000, Maine's electric utilities were responsible for generating power. In some cases, prior to deregulation, the utilities signed long term contracts for the purchase of energy from facilities that eventually became too expensive to compete in the competitive generation market. Because the costs associated with uneconomic generation units were approved by the MPUC as recoverable by the utility, such facilities became "stranded" by the transition to a competitive market for generation. Today, the MPUC regularly conducts reviews of these costs to ensure that they are legitimate and that the utilities are making bona fide attempts to reduce them.

In order to promote renewable energy, the MPUC has directed Maine's transmission and distribution utilities to enter into long-term contracts to purchase energy generated from certain Maine renewable energy projects. The utilities are permitted to resell the energy into the New England wholesale market and any difference between the purchase price and the resale price is reflected in stranded cost rates.[98]

Additionally, the stranded costs charge category may also include net energy billing tariff and program costs, a low-income assistance program, and other costs approved by the MPUC.[99,100]

## 7.2 Ratemaking

In Maine an electric utility rate case begins when a utility files a petition with the MPUC to modify its rates and charges. The time between rate cases for a given utility can vary, as there is no requirement for utilities to file rate cases with particular frequency. However, a utility may not file a schedule for a general increase in rates within one year of a prior filing for a general increase in rates, unless the proceeding initiated by a prior filing was terminated without a final determination of the public utility's revenue requirement or with approval of the commission.[101] When a utility petitions for a rate increase, it has the discretion to propose an alternative rate plan that may include MYRPs, annual adjustments based on indexed formulas and other elements.[102]

Rates for electric utilities in Maine are determined based on utilities' revenue requirement, which is the total revenue the utility needs to cover the costs of serving its customers (shown in Equation 2.1). The revenue requirement, along with the utility's billable outputs, are used to determine rates. As shown in the formula above, the revenue requirement is calculated by adding a utility's operating expenses to its rate base multiplied by an allowed rate of return. Operating expenses are costs incurred by a utility and these costs generally include employee wages and benefits, maintenance, customer services, materials and supplies, energy, and administration costs, as well as taxes and depreciation. A utility's rate base is the historical book

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[98] Maine Office of the Public Advocate. *Frequently Asked Questions.*

[99] Rules of Public Utilities Commission. Chapter 313.

[100] Maine Public Utilities Commission. *Docket 2024-00078*.

[101] Maine Statutes Title 35-A: Public Utilities, Part 1: Public Utilities Commission, Chapter 3: Rates of Public Utilities, §307.

[102] Maine Statutes Title 35-A: Public Utilities, Part 3: Electric Power, Chapter 31: General Provisions, §3195.

cost of plant-in-service less the accumulated depreciation. The allowed rate of return is set to match the utility's cost to obtain capital from lenders and shareholders.

### *Multi-Year Rate Plans*

As noted above, distribution utilities in Maine are allowed to propose alternative rate plans when petitioning for a rate increase. These alternative rate plans generally cover multiple years to reduce the frequency of utility rate cases and can be paired with forecasted or indexed rate increases. In its most recent rate case, CMP proposed to adopt a three-year Multi-Year Rate Plan (MYRP).[103] While the three-year rate plan was not ultimately adopted, the parties to the rate case agreed on a two-year rate plan with a stay-out period that would prevent the utility from initiating another rate case within this timeframe.[104]

CMP has also, in the past, operated under an indexed price cap. CMP's first price cap was implemented in 1995, and the company continued to operate under an I-X price cap for four rate plan periods until it was discontinued in 2014.[105]

A more detailed description of MYRPs and how they have been applied in other jurisdictions was presented in Section 5.

### *Revenue Decoupling*

Utilities in Maine have implemented revenue decoupling mechanisms (RDMs), which separate utilities' revenue from their sales volume. For example, CMP's RDM sets sales levels of kWh and kW based on initial targets adjusted for actual customer growth rates and a factor of 0.75.[106] Differences between the targets and actual sales levels, positive or negative, are then used to determine the revenue adjustment for that year, with annual increases capped at 2% and no cap on a rate decrease.[107] If the company sells more electricity than the target, the excess revenue is returned to customers, and vice versa.

Some of the objectives of revenue decoupling in Maine include a reduction of the financial risk of the utilities and the mitigation of disincentives that utilities might otherwise have to support energy-efficiency measures.[108] CMP first started operating under revenue decoupling in 2014.[109] Since then, CMP's revenue decoupling mechanism has undergone multiple extensions and adjustments, with the most recent approval occurring in their latest rate case.[110] MPUC has also approved a revenue decoupling mechanism for Versant Power in a 2021 decision.[111] Similar to

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[103] Maine Public Utilities Commission. *Docket No. 2022-00152. Central Maine Power Rate Application*. August 11, 2022.
[104] Maine Public Utilities Commission*. Docket No. 2022-00152. Order Approving Stipulation.* June 6, 2023.
[105] Maine Public Utilities Commission. *Dockets No. 92-00345, No. 99-00666, No. 2007-00215 and No. 2013-00168.*
[106] Maine Public Utilities Commission. *Docket No. 2022-00152. Order Approving Stipulation*. June 6, 2023.
[107] Any under-collection amount over the annual cap is deferred for recovery in a subsequent year.
[108] Maine Public Utilities Commission. *Docket 2020-00159.* December 16, 2020.
[109] Maine Public Utilities Commission. *Docket No. 2013-00168. Order Approving Stipulation*. August 25, 2014.
[110] Maine Public Utilities Commission. *Docket No. 2022-00152. Order Approving Stipulation*. June 6, 2023.
[111] Maine Public Utilities Commission. *Docket No. 2020-00316*. *ORDER (Part I).* October 18, 2021.

CMP's RDM, the decision limits any revenue decoupling related annual rate increases to 2%, while adjustments that result in rate decreases are not limited.

Section 6.3 details different revenue decoupling mechanisms, as well as information on which jurisdictions in the United States have adopted revenue decoupling.

***Earnings Sharing Mechanism***

Earnings sharing in Maine was first introduced with CMP's alternative rate plan effective in 2001, which included asymmetrical earnings sharing mechanism (ESM) that would allow utilities to recover revenue deficiencies should the Return on Equity (ROE) fall below a certain threshold.[112] While the application of a downward-only ESM is uncommon, it was included to balance the increased risk that came with the adoption of a high productivity offset.[113] In CMP's subsequent rate case, the ESM was adjusted to only share utilities overearnings.[114] With the discontinuation of the price cap plan in 2014, the ESM was also discontinued. However, CMP reintroduced an ESM in the Company's most recent rate case in 2023.[115] Versant Power does not currently operate with an ESM.

CMP's recently adopted asymmetrical ESM requires the utility to share 50% of their distribution earnings that exceed an ROE of 10.35% (100 bps above their allowed ROE of 9.35%) with no sharing for revenue deficiencies. The earnings sharing calculation considers any applicable reconciliation mechanisms and is included in CMP's annual compliance filing process. [116]

***Cost Trackers***

The MPUC is familiar with the application of costs trackers to facilitate timely recovery of certain pre-approved costs that are incurred by utilities. Cost trackers adjust customer rates between rate cases to recover costs that utilities have limited control over, or to recover costs associated with certain capital investments. Adjustments to rates related to cost trackers are made on annual basis with a requirement for utilities to file annual reconciliation or compliance reports.

In its most recent rate case, CMP proposed to implement Capital Adjustment Mechanisms (a form of capital tracker), but this proposal was not agreed upon in the stipulation and was therefore not included in the rate plan.[117] Similarly, Versant Power requested cost tracker treatment of storm costs, but this proposal was not approved.[118]

Due to the "lumpy" nature of capital additions, capital trackers and other capital expense adjustment mechanisms are commonly discussed with the application of PBR. Examples of how capital expenses are handled in different jurisdictions within a PBR context are available Subsections 6.1 and 5.2.5.6.

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[112] Maine Public Utilities Commission. *Docket No. 1999-00666. Order Approving Stipulation. November 16, 2000*.
[113] *Ibid.*
[114] Maine Public Utilities Commission. *Docket No. 2007-00215. Order Approving Stipulation*. July 1, 2008.
[115] Maine Public Utilities Commission. *Docket No. 2022-00152. Order Approving Stipulation.* June 6, 2023.
[116] Maine Public Utilities Commission. *Docket No. 2022-00152. Stipulation.* May 31, 2023.
[117] Maine Public Utilities Commission. *Docket No. 2022-00152. Stipulation.* May 31, 2023.
[118] Maine Public Utilities Commission. *Docket No. 2023-00336*. *Order*. March 13, 2025.

### *Service Quality Indicators (Indices) and Oversight*

Maine's regulated utilities face service quality regulation via Service Quality Indicators (SQIs): measurable standards by which the MPUC evaluates the performance of distribution utilities. These indicators encompass a range of metrics including reliability indices such as Customer Average Interruption Duration Index (CAIDI) and System Average Interruption Frequency Index (SAIFI), customer service response times and billing accuracy. By establishing clear SQI benchmarks and financial penalties for underperformance, the MPUC aims to incentivize utilities to maintain acceptable levels of service. The SQIs currently in place in Maine are very much structured like traditional PIMs. They have a clear performance target that the utilities have to maintain and failure to maintain these performance targets results in penalties. Table 7.2 provides an overview of SQIs currently in place in Maine.

**Table 7.2: Summary of Service Quality Indicators[119,120]**

| Service Quality Indicator (Index) | Central Maine Power | Versant Power | Description[121] |
|---|---|---|---|
| SAIFI | Yes | Yes | Average frequency of sustained interruptions per customer over a predefined area. |
| CAIDI | Yes | Yes | Average time required to restore service to the average customer per sustained interruption. |
| Calls Answered in 30 Seconds | Yes | Yes | Share of calls answered by a live person within 30 seconds. It is calculated excluding major event days. |
| Abandoned Calls | Yes | Yes | Share of calls abandoned. A call is considered "abandoned" if the caller hangs up after the call is received by the utility's automated call answering system and after the customer makes a choice to speak with a live person. |
| Estimated Bills | No | Yes | Share of bills that are estimated. A bill is considered estimated when an actual meter read is not obtained. The share is calculated by dividing the number of estimated bills with the total number of bills issued. |
| Bill Accuracy | Yes | Yes | A bill is considered erroneous if: (1) it contains an incorrect rate or charge or charge or is issue to the wrong customer; (2) it lacks a proper charge, fee, or tax; (3) total amount due is not correct; or (4) it is sent to the customer within ten days of the scheduled monthly billing date. |
| Field Service Requests | No | Yes | Timeliness of responses to field requests. |

Both CMP and Versant Power operate under a point system that determines annual rate adjustments. Each SQI is assigned a point value (weight) that determines the maximum penalty (cap) for a given SQI. The penalty amounts are based on the magnitude of underperformance, so that utilities have an incentive to minimize underperformance. For example, underperformance of 3% for a given SQI would lead to a lower penalty than an underperformance of 6%.

[119] Maine Public Utilities Commission. *Docket No. 2023-00336. Examiners' Report*. February 18, 2025.
[120] Maine Public Utilities Commission. *Docket No. 2022-00152. Stipulation*. May 31, 2023.
[121] Maine Public Utilities Commission. *Docket No. 2022-00255*. Stipulation. May 18, 2023.

A key difference between the SQIs applied to CMP and Versant Power is that CMP can offset part of the penalty amount by exceeding performance targets in other SQIs within the same category. SQIs applied to CMP are divided into two categories: (1) reliability metrics, and (2) customer service metrics. Positive performance in each category can only be used to offset penalties within the same category, and improvements in performance are awarded fewer points than a reduction in performance of an equivalent magnitude. For example, the utility receives 2.5 points for 1% improvement in performance and receives -10 points for 1% reduction in performance.

Both utilities are required to file annual compliance reports that include performance metrics and their achievement. The penalties (if applicable) are applied on annual basis.

More detailed information on PIMs and examples of PIMs applied in other jurisdictions is available in Section 4 of this report.

***Comparison of Ratemaking Elements***

Table 7.3 provides an overview of different ratemaking elements currently applied to each IOU in Maine.

**Table 7.3: Comparison of Ratemaking Elements**

| Mechanism | Central Maine Power | Versant Power |
|---|---|---|
| Revenue Decoupling | Yes | Yes |
| Cost Trackers | Yes | No |
| PIMs or SQIs | Yes | Yes |
| Multi-Year Rate Plans | Yes | No |
| Earnings Sharing Mechanism | Yes | No |

## 7.3 Regulatory Goals in the State of Maine

Articulating the regulatory goals of the state of Maine is a necessary antecedent to assessing potential changes to the existing regulatory framework. A clear set of goals helps to steer policy toward optimizing for the outcomes valued by utilities and their stakeholders. Once a set of goals is established, appropriate regulatory instruments—including, but not limited to, PBR tools—can be identified that could address those goals.

In its assessment of regulatory tools, the MPUC seeks to consider the following objectives:

1. Promote efficient and cost-effective transmission and distribution utility operations;
2. Increase planning and preparation for extreme weather events and climate hazards;
3. Promote cost-effective and comprehensive responses to outages;
4. Increase affordability and customer empowerment and satisfaction;
5. Support achievement of the State's goals for increasing consumption of electricity from renewable resources;
6. Advance the State's greenhouse gas emissions reduction goals established; and
7. Advance beneficial electrification.

These goals are overarching regulatory goals, and are not necessarily specific to the introduction of new PBR elements in Maine. In other words, we do not propose to introduce PBR tools that address each of these goals.

Climate policy currently informs the state's goals for utility regulation (see objectives 5 through 7 in the list above). Legislation in Maine requires the state to use 80 percent renewable energy by 2030, and the government has a goal of transitioning to 100 percent clean energy by 2040.[122] Most of these emissions reductions will need to occur through changes in power generation, which is unregulated and therefore beyond the jurisdiction of the MPUC. PBR tools that aim to address climate initiatives have been applied to distribution utilities in other jurisdictions, indicating that incremental modifications to the existing regulatory framework could address climate goals. However, the effect on emissions of incentives on distribution companies is likely to be small.

The goals set forth by the MPUC, listed above, align with other jurisdictions that are considering updates to electric utility regulation. For example, in its Advancing Performance Based Rate Regulation consultation, the Ontario Energy Board is currently exploring mechanisms that could promote enhanced reliability, affordability, and sustainability through the current energy transition.[123] We think these seven objectives reasonably cover the goals underlying rate regulation.

## 7.4 Industry Outlook

Maine's electric utilities are navigating a complex landscape with significant near- and long-term uncertainties shaped by infrastructure investments, electrification trends, evolving consumption patterns, and broader economic challenges. Utilities are actively pursuing significant infrastructure upgrades, as evidenced by recent rate cases,[124,125] to replace aging grid infrastructure. Maine's utilities are also navigating a shift toward beneficial electrification, driven by policies aimed at promoting energy efficiency and reducing carbon emissions.[126] These policies combined with financial incentives from third parties,[127] are encouraging the adoption of electric vehicles, heat pumps, and other electric technologies, which can lead to increased electric demand requiring utilities to plan for higher loads.

As electrification accelerates, Maine's historical trend of declining energy consumption since the mid-2000s may slow or even reverse;[128] particularly with the growth of energy-intensive industries such as data centers. This shift in electricity consumption patterns requires strategic planning by utilities to ensure the grid can efficiently manage uncertain loads.

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122 Maine Climate Council. *Maine Won't Wait: A Four-Year Plan for Climate Action*. November 2024.

123 Ontario Energy Board. *Advancing Performance-based Rate Regulation*. Ongoing work that began in 2024.

124 Maine Public Utilities Commission. *Docket 2022-00152*. August 11, 2022.

125 Maine Public Utilities Commission. *Docket 2020-00316*. January 19, 2021.

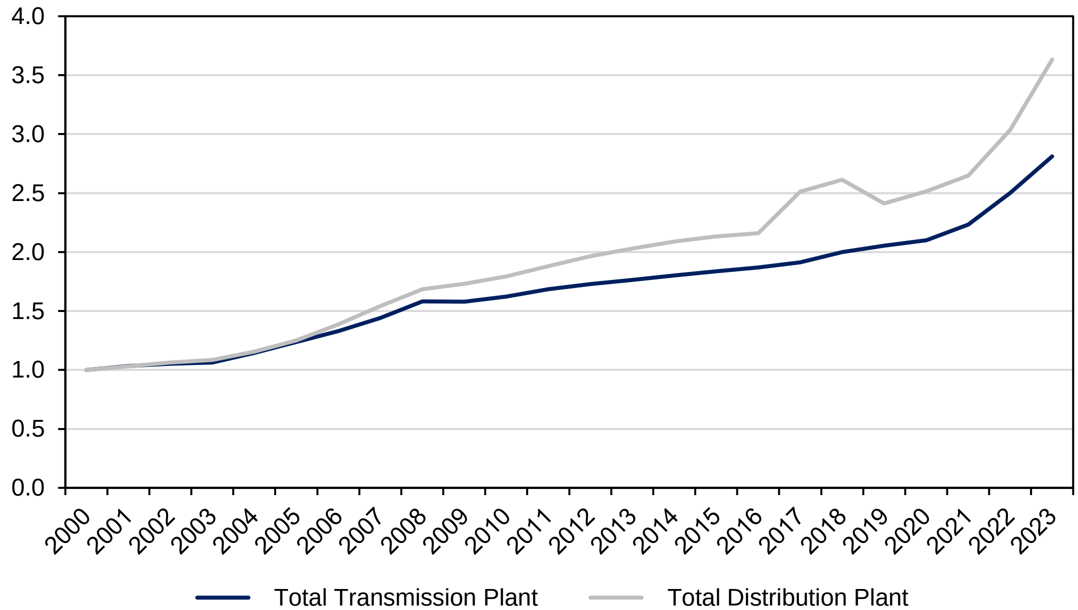
126 Maine State Legislature. Title 35-A, Chapter 38: Beneficial Electrification Policy Act

127 Efficiency Maine. *At Home: Residential Incentives*.

128 U.S. Energy Information Administration. State Energy Data System (SEDS).

In addition, cost pressures have accelerated across the industry. Figure 7.2 below presents a utility industry cost index (known as the Handy-Whitman Index[129]) tracking Total Transmission and Distribution Plant in the North Atlantic region since 2000. The data shows substantial growth in costs over the past quarter century, with a noticeable uptick since the Covid-19 pandemic. Utilities facing these cost pressures and customers paying rates could benefit from indexed cap or forecasted MYRPs, which might encourage cost efficiency while providing a reasonable level of attrition relief.

**Figure 7.2: Handy Whitman Index – Total Transmission and Distribution Plant**




Ongoing tariffs between the United States and Canada create considerable uncertainty around imports and present an additional challenge for the state of Maine's energy supply. ISO New England imports electricity from Canada,[130] and the tariffs, could lead to broader ripple effects in the economy. The duration of these tariffs and their long-term impacts remain unclear, but given the deep interconnection between the two economies, the effects could extend beyond short-term price fluctuations and potentially influence longer-term consumer behavior and market trends.

[129] The Handy-Whitman Index tracks constructions costs for utility companies across different U.S. regions and is widely recognized by utility companies and regulatory bodies as an authoritative reference for utility cost trends.

[130] Grid Status. *Tariffs Challenge the Interconnected Northeast.* March 5, 2025.

## 7.5 Could Additional PBR Tools Provide Improvements for Utilities and Customers in Maine?

The MPUC commissioned this study to understand whether PBR tools may be used to address Maine's policy goals for the state's electric utilities, as discussed in Subsection 7.3.

One of the central findings of this report is that the MPUC has already incorporated several PBR elements into its ratemaking structure. These include MYRPs, for example CMP's current MYRP and the company's former price cap, and PIMs in the form of SQIs, which apply to both utilities. Since some PBR elements are already in place in Maine, a question is whether additional PBR tools would assist the state in furthering its regulatory objectives. Newly adopted legislation in the state has granted the Commission with authority to "establish or authorize rate-adjustment mechanisms or quantitative metrics pertaining to public utility's operations and activities in a proceeding for a general increase in rates".[131]

The first step to answering this question is to consider the state's policy goals. As described in Section 7.3, PBR tools have been considered and implemented in other jurisdictions to address policy initiatives similar to the objectives of the MPUC. Some of these regulatory approaches could be introduced to Maine, and others that already exist as options in Maine could be formalized or made mandatory. For example, by formalizing a basic structure for MYRPs and requiring the state's utilities to follow this structure, the MPUC could create a regulatory framework in which utilities might gain more predictable revenues and obtain stronger incentives for cost control and innovation, while consumers might benefit from more stable rates, improved utility performance, and the potential for lower rates in the long run as efficiency gains are shared. Formalizing MYRP guidelines could encourage utilities to exercise optional Alternative Rate Plans by reducing the risk that a proposed approach might be rejected.

New PIMs could be used to target specific policy related to the energy transition. These PIMs could include reward -only financial incentives to encourage action beyond traditional utility expectations.

However, while PBR may provide improvements to the status quo regulatory framework, the introduction of new PBR tools does not guarantee improvements. The realization of benefits from PBR requires a well-structured design that accounts for the particular circumstances of the jurisdiction or utility. For this reason, while case studies offer valuable insights, plans that prove successful elsewhere cannot be assumed to replicate that success if applied identically in Maine.

The following two subsections describe PBR tools that might or might not be suitable in Maine, drawing from other jurisdictions where utilities operate under PBR.

### *7.5.1 PBR Tools for Maine's Consideration*

Maine's IOUs are "lines-only" utilities, which means they do not own generation plant. As a state where the IOUs own only transmission and distribution plant, Maine is similar to other jurisdictions where the utilities operate under indexed caps (i.e. price caps or revenue caps). In

[131] "An Act to Allow the Public Utilities Commission to Establish Performance-based Metrics and Rate-adjustment Mechanisms for a Public Utility in Any Proceeding," LD 301, Passed June 2, 2025.

fact, most utilities that operate with an indexed cap are lines-only utilities.[132] This, along with past experience with price caps in the state,[133] suggests that indexed cap PBR could be a viable option for Maine. Section 5.2 provides more detail on how to construct an indexed cap MYRP.

As is the case in Maine, lines-only utilities can also operate under PIMs. While PIMs in Maine only assess a penalty on utilities, with no potential reward, many jurisdictions that have implemented PIMs have adopted reward-only or symmetrical PIMs. Often, PIMs with financial rewards aim to encourage investment or action related to non-traditional utility service, such as meeting policy objectives associated with the energy transition or addressing climate goals. For example, lines-only utilities in Australia, Great Britain, Illinois, and New York operate under targeted mechanisms that provide financial rewards for utility performance in achieving new policy objectives. Section 4.6 provides more detail on these examples. Such jurisdictions could offer a helpful guide to Maine if the state is interested in building on its existing service quality indicators.

While the organization of the state's electricity industry shares some similarities with other jurisdictions that have adopted PBR, this does not mean that identical regulatory tools make sense for Maine. We recommend that the MPUC, utilities, and stakeholders collaborate to determine what new PBR tools make sense to adopt, using this report as a guide.

### *7.5.2 Limitations to New PBR Tools in Maine*

Not all PBR tools make sense to introduce in Maine, and if some tools are adopted, they should be tailored to the state's industrial organization.

Maine's regulated electric utilities own transmission plant within the Independent System Operator of New England (ISO-NE). As discussed throughout this report, utilities that own transmission plant may have larger, lumpier capital investments that could be challenging to regulate under an indexed approach to rate regulation.[134]

In addition, transmission projects for Maine's IOUs are, to a large degree, directed by ISO-NE. As such, substantial portions of the transmission investments made by Maine's IOUs are beyond the control of utility management. In Ontario, electricity distributors operate within the province's Independent Electric System Operator and face indexed cap regulation, but a key difference between Maine and Ontario is that the distributors in Ontario do not own transmission plant.[135] A lack of control over capital projects can make indexed cap regulation more challenging, as the utility may have less ability to manage when and where to make investments. As such, indexed cap PBR, if adopted in Maine, should be accompanied by factors that allow for the recovery of

[132] See for example, Alberta, Ontario, British Columbia (gas distribution only), and Massachusetts. The only vertically integrated electric utility in North America currently operating under an indexed cap is the Hawaiian Electric Companies.

[133] Central Maine Power operated under a price cap until 2014.

[134] Hydro-Québec TransÉnergie, the transmission company in Québec, operated for one four-year period under a revenue cap, but subsequently returned to cost-of-service regulation in 2022 amid issues meeting necessary costs under the cap.

[135] To the extent that the ownership of transmission creates an impediment to adopting price or revenue cap regulation in Maine, an alternative approach could be developed that caps only revenues associated with distribution plant—leaving the transmission portion of the business to remain under traditional COSR. Of course, this may create more administrative complications than its worth.

costs beyond utility management's control (e.g., Y factors, Z factors, and, possibly, capital supplements).

Some jurisdictions, like Hawaii, North Carolina, and Washington state, have implemented PBR tools that make sense for vertically integrated electric utilities,[136] but would make less sense for a lines-only company. Fundamental differences in the industry structure in these jurisdictions mean that the applicable tools in these states likely differ from what can be expected to work in Maine. For example, utilities that own generation plant have more control over the generation mix, and therefore greenhouse gas (GHG) emissions, than utilities that only own distribution plant (like the IOUs in Maine). A PIM aimed at addressing GHG emissions may not work as well in Maine because the utilities do not have ownership of generation assets, and therefore, even strong financial incentives to the utility are unlikely to result in substantive changes to emissions related to power generation. Lines-only utilities can still influence the demand side through the implementation of demand response programs and interconnection of Distributed Energy Resources (DERs), but the effect is likely smaller.

The criteria presented in Section 4.2 can be used to screen potential PIMs. For example, in proposing new PIMs, the IOUs should consider on-going initiatives in Maine, and these PIMs should track outcomes that the utility can reasonably control. In addition, the Efficiency Maine Trust has statutory authority to develop, plan, coordinate, and implement energy efficiency, beneficial electrification and demand management programs in the state, while utilities in Maine play a supporting role in these efforts. This means that some PIMs that may be workably applied to utilities in other states (for example, certain PIMs discussed in Section 4.6) may not be applicable in Maine because the initiatives fall under the purview of the Efficiency Maine Trust.

The design of MYRPs and PIMs in Maine should acknowledge these limitations. MYRPs should allow for exogenous cost factors and possibly allow for transmission to be handled separately from distribution-related costs. In accordance with PIM design considerations described in Section 4.2, new PIMs should address performance that can be controlled by a lines-only utility.

## 7.6 Stakeholder Input

A draft of this report was published on April 30, 2025.[137] Subsequently, the Maine PUC held a stakeholder engagement workshop on May 14, 2025. Through this workshop, and through written comments, we received helpful feedback from stakeholders that have informed the final version of this report. Some stakeholders commented that PIMs should consider how the utilities' role in demand management programs, energy efficiency, and beneficial electrification differ from utilities in other jurisdictions. Since ratepayers already bear the costs for Efficiency Maine Trust programs, they should not be paying twice for the same initiative.

In addition, stakeholders noted that the challenges of developing reliable baseline data for metrics associated with PIMs must be considered. The introduction of new metrics is not a costless endeavor: the IOUs must expend resources (paid for by ratepayers) in order to create

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[136] National Association of Regulatory Utility Commissions (NARUC). *Tracking State Developments of Performance-Based Regulation. PBR State Working Group.* January 2024.
[137] Filed under Docket 2025-00107.

the systems for recording, processing, and reporting data. The calibration of financial incentives also involves development costs.

Stakeholders commented that PBR frameworks need to be carefully designed, as poorly designed framework can create perverse incentives for the utilities. While PBR tools are helpful to address some regulatory goals listed in Section 7.3, given Maine utilities are "lines-only" utilities, other policy tools may be more appropriate to address goals related to greenhouse gas emissions, renewable energy, and beneficial electrification.

Regarding the policy goals, one stakeholder suggested separating "affordability" from goal #4, so that affordability and customer empowerment might be considered separately. Other suggestions were also made regarding the state's regulatory goals.

# 8 SUMMARY OF RECOMMENDATIONS AND CONCLUSIONS

Electric utilities in the state of Maine already operate under some form of PBR. The existing SQIs provide financial incentives to maintain reliability and customer service quality. We conclude that these tools meet the definition of PIMs, which are PBR tools that provide incentives for the efficient deployment of specific utility outputs. Utilities in Maine also have flexibility to propose MYRPs under an "Alternative Rate Plan." This means that, under the current framework, both CMP and Versant Power could choose to file an indexed cap PBR plan or a forecasted MYRP. The state's approach to the regulation of these companies is similar to other states in the Northeast, like Massachusetts, where utility rate plans with or without PBR elements are assessed on a case-by-case basis.

Additional PBR tools could be introduced in Maine. The MPUC could introduce new PIMs aimed to address certain policy objectives. In addition, the state could standardize requirements for MYRPs. PIMs and MYRPs are generally compatible, but these elements need to be evaluated as a whole. Some consideration should be made on how new regulatory tools affect the utility's cost of capital, as well as the potential cost and benefit to customers.

While the introduction of new tools may provide benefits to customers and to the utilities, these tools also have limitations and drawbacks. This report provides a detailed analysis of the benefits and challenges of the additional PBR tools the MPUC could consider introducing.

## 8.1 Summary of MYRP Recommendations

Maine IOUs are already permitted to file MYRPs as an alternative rate plan.

Evidence from other jurisdictions indicates that MYRPs can improve utility cost control over time. The organization of the electricity distribution industry in Maine resembles other jurisdictions in North America, as well as in Europe, and Australia, where MYRPs have been implemented successfully in the distribution sector. This finding suggests that indexed cap or forecasted MYRPs, if designed well, are likely to address stakeholder affordability and cost control concerns in the state of Maine. As shown in Table 8.3, we encourage the state's IOUs to voluntarily propose indexed cap MYRPs, and we encourage the Maine PUC to accept well-designed indexed cap plans. Table 8.4 presents tenets for a well-designed indexed cap plan.

Alternatively, forecasted MYRPs offer an approach that can provide the regulator with more spending oversight while providing cost efficiency incentives. However, this approach requires the utility to provide clear cost forecast information, and it requires resources from stakeholders to evaluate those spending forecasts.

Cost efficiency incentives through MYRPs may help with affordability but will not resolve all factors driving customer rate increases. A substantial portion of customer rates pertains to generation services, which Maine's IOUs do not provide.

## 8.2 Summary of PIM Recommendations

Maine's IOUs already operate under mechanisms akin to PIMs under than name Service Quality Indicators (SQIs). These include penalty-only financial incentives for seven measures spanning reliability and customer service. Maine could consider adopting reward-only or symmetrical PIMs to address policy goals currently not addressed in the existing regulatory framework.

We recommend that before instituting any additional PIMs, the MPUC determine which specific policy goals might be addressed by PIMs and meet with stakeholders to discuss potential benefits and drawbacks of attaching financial incentives to related metrics. In the meantime, the MPUC should allow the state's IOUs to propose PIMs on a case-by-case basis as part of the current rate application process.

Table 8.7 summarizes our recommendations regarding PIMs in the state of Maine.

## 8.3 Recommendation Tables

The tables below comprise the recommendations presented in this report.

**Table 8.1: Summary of Guiding PBR Principle Recommendations**

| | |
|---|---|
| Guiding Principles of PBR | *The seven regulatory goals set forth in Section 7.3 stem from the draft legislative language that prompted this investigation. These goals provide an adequate basis for evaluating the regulatory frameworks applied to Maine IOUs, PBR or otherwise.* |

**Table 8.2: Summary of Revenue Decoupling Recommendations**

| | |
|---|---|
| Revenue Decoupling | *The objective of this report was not to evaluate the existing revenue decoupling mechanisms of the Maine IOUs. However, we note that if an IOU develops a MYRP, the design of the framework must consider the interaction between the RDM and the MYRP.* |

**Table 8.3: Summary of MYRP Recommendations**

| | |
|---|---|
| Recommendations for MYRPs in Maine | *Maine IOUs are already permitted to file MYRPs as an alternative rate plan. To provide cost efficiency incentives to the utilities, we encourage the adoption of either forecasted or indexed cap MYRPs.*<br><br>*Furthermore, we note that, as "lines-only" utilities, IOUs in Maine may be well-suited for indexed cap (price cap, revenue cap, or hybrid) PBR frameworks, as these plans provide cost efficiency incentives that may improve customer affordability. We therefore encourage the state's IOUs to voluntarily propose indexed cap MYRPs, and we encourage the Maine PUC to accept well-designed indexed cap plans (with further recommendations in Table 8.4).* |

**Table 8.4: Summary of Indexed Cap Recommendations**

| | |
|---|---|
| Indexed Caps | *We encourage the Maine IOUs to propose, and the Maine PUC to accept, indexed cap plans rooted in the I-X formula.* |
| Indexed Cap Inflation Factors | *If the Maine IOUs operate under an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that an inflation factor be included in the PBR formula (I-X). The inflation factor should be established to reflect the electric utility sector's annual input price growth. If an output price measure of inflation is used, the X factor must be adjusted accordingly.* |
| Indexed Cap X Factors | *If the Maine IOUs operate under an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that an X factor be included in the PBR formula (I-X). This X factor should be calculated on the basis of an industry TFP growth or Kahn Methodology.* |
| Indexed Cap Stretch Factors | *If the Maine IOUs operate under an indexed cap approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a stretch factor be included in the formula (I-X-S). This stretch factor should be company-specific informed by an industry cost benchmarking analysis.* |
| Z Factors | *If the Maine IOUs operate under an indexed cap or forecasted MYRP approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a Z factor be included in the PBR framework. The Z factor should be* |

| | |
|---|---|
| | *company-specific and have a materiality threshold roughly in line with thresholds seen in other jurisdictions.* |
| Y Factors | *If the Maine IOUs operate under an indexed cap or forecasted MYRP approach to PBR or a hybrid approach that places some portion of revenue under a cap, we recommend that a Y factor be included in the PBR framework. The Y factor should be company-specific and the costs eligible for Y factor treatment should be clearly defined at the outset of the PBR term.* |
| Capital Factors | *If the Maine IOUs operate under an indexed cap regulatory framework, we recommend that some form of capital supplement be included on an as-needed basis. The capital factor should be company-specific and the costs eligible for capital factor treatment should be clearly defined at the outset of the PBR term. We recommend adopting capital factors that provide cost efficiency incentives, such as a forecasted capital or K-bar approach, when possible.* |
| Reopeners | *If the Maine IOUs operate under an indexed cap regulatory framework or a forecasted MYRP, we recommend that some form of reopener be included. The reopener provision should have a clearly defined trigger and a clear description of how the mechanism would be applied in the event of being triggered.* |
| Earnings Sharing Mechanisms (ESM)s | *If the Maine IOUs operate under an indexed cap regulatory framework or a forecasted MYRP, utilities or utility stakeholders may wish to incorporate ESMs. ESMs are not necessary elements of a regulatory framework. However, if ESMs are adopted, we recommend wide deadbands in order to maintain cost efficiency incentives. For example, sharing only after a 200+ basis point deviation from allowed ROE.* |
| Efficiency Carryover Mechanisms (ECMs) | *If the Maine IOUs operate under a MYRP regulatory framework, we recommend consideration of Efficiency Carryover Mechanisms as a way to maintain cost efficiency incentives over rebasing periods.* |

**Table 8.5: Summary of Forecasted MYRP Recommendations**

| | |
|---|---|
| Forecasted MYRPs | *We recommend Maine IOUs continue to be permitted to voluntarily file forecasted MYRPs. We further recommend consideration of MYRP terms longer than the two-year plan currently applied to CMP (for example, three or four years). We note that indexed cap plans may offer more simplicity and better cost efficiency incentives, depending on the plan design.*<br><br>*If three- or four-year forecasted MYRPs are adopted, these plans may include additional elements discussed in Table 8.4. For example, exogenous cost factors (Z and Y factors) may be included, as well as reopener provisions.* |

**Table 8.6: Summary of Formula Rate Plan Recommendations**

| | |
|---|---|
| Formula Rate Plans | *We do not currently recommend that Maine IOUs pursue formula rate plans. However, if IOUs face major, lumpy investments and the frequency of rate cases becomes a problem, this is an option that could be considered.* |

**Table 8.7: Summary of PIMs Recommendations**

| | |
|---|---|
| Recommendations for PIMs in Maine | *1. We recommend that the Maine PUC allow the state's IOUs to file new PIMs as part of future rate applications, to be assessed on a case-by-case basis. We recommend using the guidelines provided in Section 4.2 in the design of these PIMs.*<br><br>*2. We recommend that before instituting any mandatory PIMs or any PIMs that apply to all IOUs, the Maine PUC determine which specific policy goals might be addressed by PIMs and meet with stakeholders to discuss potential benefits and drawbacks of attaching financial incentives to related metrics. We recommend following the criteria set out in Section 4.2 prior to implementing mandatory PIMs.* |

## APPENDIX A: GLOSSARY OF ABBREVIATIONS

| Abbreviated Term | Full Term | Abbreviated Term | Full Term |
|---|---|---|---|
| AMI | Advanced Metering Infrastructure | IOU | Investor Owned Utility |
| ARM | Attrition Relief Mechanism | ISO-NE | Independent System Operator New England |
| AUC | Alberta Utilities Commission | MISO | Midcontinent Independent System Operator |
| BCUC | British Columbia Utilities Commission | MPUC | Maine Public Utilities Commission |
| CA Energy Consulting | Christensen Associates Energy Consulting | MYRP | Multi-Year Rate Plan |
| CAIDI | Customer Average Interruption Duration Index | NYPSC | New York Public Service Commission |
| CAPEX | Capital Expenditure | NYSEG | New York State Electric & Gas |
| CMP | Central Maine Power | ODI | Output Delivery Incentives |
| COSR | Cost-of-Service Regulation | OEPX | Operating Expenditure |
| CPI | Consumer Price Index | PBR | Performance-Based Regulation |
| CSPI | Customer Service Performance Mechanism | PCR | Price Cap Regulation |
| DEC | Duke Energy Carolinas' | PIM | Performance Incentive Mechanism |
| DER | Distributed Energy Resources | PUC | Public Utilities Commission |
| EAM | Earnings Adjustment Mechanisms | PURPA | Public Utility Regulatory Policy Act |
| ECM | Efficiency Carryover Mechanisms | RDM | Revenue Decoupling Mechanism |
| EPCOE | Evaluation Period Cost of Equity | REV | Reforming Energy Vision |
| EPRM | Exceptional Project Recovery Mechanism | RIIO | Revenue using Incentives to deliver Innovation and Outputs |
| ESM | Earnings Sharing Mechanism | RMI | Rocky Mountain Institute |
| EV | Electric Vehicle | ROE | Return on Equity |
| FERC | Federal Energy Regulatory Commission | RPM | Reliability Performance Mechanism |
| FFR | Fast Frequency Response | RPS-A | Renewable Portfolio Standard-Accelerated |
| FRP | Formula Rate Plan | SAIDI | System Average Interruption Duration Index |
| FWI | Fixed Weight Index | SAIFI | System Average Interruption Frequency Index |
| GDP-PI | Gross Domestic Product Price Index | SQI | Service Quality Indicator (Index) |
| GHG | Greenhouse Gas | TFP | Total Factor Productivity |
| HECO | Hawaiian Electric Companies | TOTEX | Total Expenditure |

## APPENDIX B: INDEXED CAP DERIVATIONS

### B.1 Price Cap Derivation

The derivation for a utility's cap in price growth follows from the theory of competitive markets, as PBR attempts to induce growth in price that one would observe if the regulated company were in fact operating in a competitive market. In competitive markets, firms earn zero economic profit[138]. This is generally understood best by example; suppose a firm operates in a competitive market and is able to rent capital at a low price and use this rented capital along with labor and materials to produce goods at an output price that allows for positive economic profit. In this case, profit-seeking competing firms will enter the market and copy this strategy, bidding up the price of capital until profits are zero. Thus, it must be the case that revenues equal economic cost:

$$Revenue = Economic\ Cost$$

$$\sum p_i q_i = \sum w_j z_j$$

Where $p_i$ is the price of output $i$, $q_i$ is the number of units of output $i$, $w_j$ is the price of input $j$, $z_j$ is the number of units of input $j$, and the notation $\sum x_i$ is shorthand for $x_1+x_2+\ldots x_n$ if $i$ takes on values from 1 to $n$. For example, the utility's three billable outputs might be energy (KWh), demand (KW) and total customers. In the first case, the utility has a price per KWh ($p_{KWh}$) and a total KWh delivered to customers ($q_{KWh}$) that when multiplied together yields total revenue from energy sold. On the input side, as an example, the utility might have three input: labor, capital, and materials. If the utility hires $z_{Labor}$ employees and pays a wage of $w_{Labor}$, the cost of labor can be calculated by multiplying these terms together. Therefore, its revenue is $p_{KWh}q_{KWh}$ + $p_{demand}q_{demand}$ + $p_{customers}q_{customers}$ and its costs are $w_{labor}z_{labor}$ + $w_{capital}z_{capital}$ + $w_{materials}z_{materials}$, which can be written a compact way as shown above, for $i$ in $[KWh, demand, customers]$ and $j$ in $[labor, capital, materials]$.

The task of calibrating a price cap is to figure out how prices should move in response to exogenous changes in input price and outputs (say, demand and customer growth) to allow the utility enough revenue to cover its costs. This can be achieved by studying how the revenue equals cost relationship changes over time when prices, outputs, and inputs change:[139]

$$\sum \dot{p}_i q_i + \sum p_i \dot{q}_i = \sum \dot{w}_j z_j + \sum w_j \dot{z}_j$$

Roughly speaking, the notation $\dot{x}$ can be interpreted as the change in $x$ over time.[140] To convert this expression to growth rates rather than level changes, we can begin by multiplying and

[138] Economic profit includes opportunity cost. For instance, if a firm owns its capital, the amount it can earn in rent payments from leasing it to businesses should be included as a cost.
[139] This is derived by totally differentiating the revenue equals cost expression with respect to time.
[140] Technically, it is the derivative of $x$ with respect to time, or $dx/dt$.

dividing each term by level of the variable that has been differentiated, since this ratio is 1 and thus the equality still holds:

$$\sum \dot{p}_i q_i \frac{p_i}{p_i} + \sum p_i \dot{q}_i \frac{q_i}{q_i} = \sum \dot{w}_j z_j \frac{w_j}{w_j} + \sum w_j \dot{z}_j \frac{z_j}{z_j}$$

We can then divide the left-hand side by total revenue and the right-hand side by total cost, since these quantities are equal and so the equality still holds. We can then rewrite the expression in terms of revenue and cost shares, noting that

$r_i = \frac{q_i p_i}{Revenue}$, or output $i's$ revenue share, and

$c_i = \frac{w_j z_j}{Cost}$, or input $j's$ cost share

Doing so changes the expression to

$$\%\Delta Revenue = \%\Delta Cost$$

or,

$$\sum r_i \frac{\dot{p}_i}{p_i} + \sum r_i \frac{\dot{q}_i}{q_i} = \sum c_j \frac{\dot{w}_j}{w_i} + \sum c_j \frac{\dot{z}_j}{z_i}$$

The first term is the sum of the percentage changes in output prices, where each price is weighted by its share in revenue. It can be interpreted as the percentage change in the price index.[141] The other terms take the same form, and represent percentage changes in the output index, the input price index, and the input index, respectively. Rewriting to make this clear,

$$\%\Delta P + \%\Delta Q = \%\Delta W + \%\Delta Z$$

Solving for $\%\Delta P$,

$$\%\Delta P = \%\Delta W - (\%\Delta Q - \%\Delta Z)$$

$$\%\Delta P = I - X$$

where $I = \%\Delta W$ and $X = \%\Delta Q - \%\Delta Z$

There are several possible choices for $X$. The first choice is the company's own projected productivity growth. In this case, the company will earn zero profit essentially by design. Another choice, which is the standard approach, is to let $X$ be the average productivity growth in the industry. This latter choice forces the company to match the industry's productivity rate in order to at least break even. However, note that neither choice ideally emulates competitive markets, since the industry productivity rate is not reflective of a competitive market. This is an important part of the motivation behind the stretch factor, discussed above.

[141] This percentage change is referred to as a Tornqvist index.

In some jurisdictions it is common to use a measure of output inflation rather than input inflation. In this case, the price cap can be derived by noting that, if one assumes the economy as whole is competitive, the same relationship holds for the economy:

$$\%\Delta P_{econ} = I_{econ} - X_{econ}$$

$\%\Delta P_{econ}$ is output price inflation, which is the inflation measure used for the utility's price cap in this case. An example of $\%\Delta P_{econ}$ is the growth rate of the GDP-PI. A measure of economy-wide total factor productivity growth is estimated annually, and so together with the GDP-PI, $I_{econ}$ can be recovered as the sum of these two growth rates based on the above equation. Combining this equation with same equation derived for the average company in the industry (with the $X$ that incentivizes the firm to at least match the productivity of the average company), the two equations can be subtracted to yield

$$\%\Delta P_{ind} - \%\Delta P_{econ} = (I_{ind} - I_{econ}) - (X_{ind} - X_{econ})$$

$$\%\Delta P_{ind} = \%\Delta P_{econ} - [(I_{econ} - I_{ind}) + (X_{ind} - X_{econ})]$$

which is the appropriate price cap when a measure of output price inflation is used.

In summary, there are two common price caps, depending on whether an input or output price inflation measure is used. When the appropriate measure of input price inflation is used, the cap is

$$\%\Delta P = I_{ind} - X_{ind}$$

When a measure of output price inflation like the growth rate in the GDP-PI is used, the cap is

$$\%\Delta P = \%\Delta P_{econ} - [(I_{econ} - I_{ind}) + (X_{ind} - X_{econ})]$$

## B.2 Revenue Cap Derivation

In B.1, we derived the formula for the price cap:

$$\%\Delta P = I - X$$

This was derived by noting that, in competitive markets,

$$\%\Delta Revenue = \%\Delta Cost$$

$$\%\Delta P + \%\Delta Q = \%\Delta W + \%\Delta Z$$

Thus, $\%\Delta Revenue = \%\Delta P + \%\Delta Q$.

For a given price cap $\%\Delta P$, adding on $\%\Delta Q$ yields the corresponding revenue cap $\%\Delta Revenue$. This factor $\%\Delta Q$ is often called the "growth factor", and is represented by the term *G*.

# APPENDIX C: PBR PRINCIPLES IN OTHER JURISDICTIONS

## C.1 Alberta

Gas and electric distribution utilities in the province of Alberta have operated under PBR for over a decade. In the original decision that organized PBR in the province, the Alberta Utilities Commission published the following guiding principles:[142]

<u>Principle 1.</u> A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.

<u>Principle 2.</u> A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.

<u>Principle 3.</u> A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.

<u>Principle 4.</u> A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.

<u>Principle 5.</u> Customers and the regulated companies should share the benefits of a PBR plan.

## C.2 British Columbia

The BCUC determined that the principles listed below should guide its assessment of the efficacy of the multiyear rate plans proposed by FortisBC Energy Inc. (FEI) and FortisBC, Inc. (FBC) (together, FortisBC).[143] These principles align closely with the principles adopted by the Alberta Utilities Commission (AUC) for the PBR plans in effect in Alberta. As noted by the AUC, there is a high degree of consensus on the principles that should guide the development of PBR.

1. The PBR plan should, to the greatest extent possible, align the interests of customers and the utility; customers and the utility should share in the benefits of the PBR plan.

2. The PBR plan must provide the utility with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.

3. The PBR plan should recognize the unique circumstances of the company that are relevant to the PBR design.

4. The PBR plan should maintain the utility's focus on maintaining safe, reliable service and customer service quality while creating the efficiency incentives to continue with its productivity improvement culture.

[142] Alberta Utilities Commission. *Regulated Rate Initiative – PBR Principles*, *AUC Bulletin 2010-20*. July 15, 2010. p. 2.
[143] British Columbia Utilities Commission. *Application for Approval of a Multi-Year Rate Plan for the Years 2020 through 2024*, *Decision and Orders G-165-20 and G-166-20*. June 22, 2020. p. 168.

5. The PBR plan should be easy to understand, implement, and administer and should reduce the regulatory burden over time.

## C.3 Ontario

In its Renewed Regulatory Framework, the Ontario Energy Board concluded the following outcomes are appropriate for consideration when evaluating utility rate applications.[144]

1. Customer Focus: services are provided in a manner that responds to identified customer preferences;
2. Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
3. Public Policy Responsiveness: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
4. Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable

## C.4 Massachusetts

In addition, the Department established a number of factors it would weigh in evaluating incentive proposals. These factors provide that a well-designed incentive proposal should:[145]

1. Comply with Department regulations, unless accompanied by a request for a specific waiver;
2. Be designed to serve as a vehicle to a more competitive environment and to improve the provision of monopoly services;
3. Not result in reductions of safety, service reliability, or existing standards of customer service;
4. Not focus excessively on cost recovery issues;
5. Focus on comprehensive results;
6. Be designed to achieve specific, measurable results; and
7. Provide a more efficient regulatory approach, thus reducing regulatory and administrative costs. These objectives mesh with the guiding principles of PBR established in other jurisdictions.

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[144] Ontario Energy Board. *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*. October 18, 2012. p. 57.
[145] Massachusetts D.P.U. *Docket 94-158*. p. 57.

## C.5 Hawaii

PBR Guiding Principles:[146]

1. A customer-centric approach. A PBR framework should encourage the expanding opportunities for customer choice and participation in all appropriate aspects of utility system functions, including verifiable "day-one" savings for customers.
2. Administrative efficiency. PBR offers an opportunity to simplify the regulatory framework and enhance overall administrative
3. Utility financial integrity. The financial integrity of the utility is essential to its basic obligation to provide safe and reliable electric service for its customers and PBR framework is intended to preserve the utility's opportunity to earn fair return on its business and investments, while maintaining attractive utility features such as low cost capital.

[146] Hawaii Public Utilities Commission. *Decision and Order No. 36326*. May 23, 2019. p. 6.